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November 12, 2015

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, D.C. 20426

Re: PJM Interconnection, L.L.C., Docket No. ER16- 316 *-000*
Ministerial Clean-up Filing – Various Sections of the Tariff, Operating Agreement and RAA.

Dear Ms. Bose:

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, PJM Interconnection, L.L.C. ("PJM") hereby submits to the Commission revisions to the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") and the PJM Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA") to incorporate previously accepted revisions which would otherwise not be reflected in the Tariff, Operating Agreement and RAA as of April 1, 2015, May 11, 2015, July 13, 2015 and August 3, 2015 due to the overlapping timing of certain PJM filings. PJM requests an effective date of April 1, 2015, May 11, 2015, July 13, 2015 and August 3, 2015, for the proposed revisions, consistent with the effective dates previously approved as discussed below. No substantive changes to the Tariff, Operating Agreement and RAA are being made in this filing.

I. BACKGROUND AND PERTINENT PJM FILINGS

Because of the timing and effective dates of seven recent PJM filings, which among other things amended seventeen sections in the Tariff, Operating Agreement or RAA, not all of the Commission-accepted revisions to these sections will be reflected in the current effective version of the relevant sections. Therefore, PJM submits this ministerial filing to ensure the accuracy of the Tariff, Operating Agreement and RAA. Additionally, PJM is submitting some of the sections to simply reflect that the language has been accepted and is no longer pending language. For these sections, the ministerial change is simply changing the text from italicized to plain text. The pertinent filings and their respective effective dates are discussed in more detail below.

On December 12, 2014, in Docket No. ER15-623-000, submitted proposed reforms to the Reliability Pricing Model ("RPM") and related rules in the PJM Tariff and RAA to better ensure that committed capacity resources will perform when called upon to meet the reliability needs of the PJM Region ("ER15-623 Filing"). The proposed revisions included revisions to the following sections: Table of Contents, Definitions E-F, Attachment K-Appendix sections 1.3, 1.10, 3.2 and 5.2, Attachment Q, Attachment DD.2, DD 5.12, DD 5.14 and DD-1 of the Tariff; and Schedule 6 of the RAA. Additionally, on December 12, 2014, in Docket No. EL15-29-000, PJM submitted proposed revisions to the Operating Agreement and related revisions to the Tariff to correct deficiencies on issues of resource performance, in the wholesale markets administered by PJM. Specifically, PJM proposed reforms regarding offers into PJM's Day-ahead Energy Market (including parameter limits on such offers), force majeure provisions applicable to market participant performance, and planned and maintenance outage rules ("EL15-29 Filing"). The proposed revisions included revisions to Definitions C-D, Schedule 1 sections 1.3, 1.10, 3.2 and 5.2 of the Operating Agreement. On June 9, 2015, the Commission issued an order accepting, subject to compliance filing, PJM's ER15-623 Filing and EL15-29 Filing with an effective date of April 1, 2015. On July 9, 2015, pursuant to the Commission's June 9, 2015 order, PJM submitted its required compliance filing in ER15-623-004 including revisions to Attachment Q, Attachment DD.2, Attachment DD-1 of the Tariff and Schedule 6 of the RAA. Also on July 9, 2015, PJM submitted a compliance filing in EL15-29 with changes to Attachment K-Appendix sections 1.10 and 3.2 as well as the parallel sections of Schedule 1 of the Operating Agreement. PJM requested an April 1, 2015 effective date for this compliance filing. Additionally, on July 28, 2015, PJM filed a second compliance filing, in ER15-623-006, which included changes to Attachment DD 5.14 in response to the Commission order that PJM allow Demand Response and Energy Efficiency Resources participate in the Capacity Performance transition auctions. PJM requested a July 22, 2015 effective date for the second compliance filing. Finally, on October 27, 2015, in Docket No. ER15-623-008, PJM submitted a further compliance filing that included revisions to OATT Attachment DD-1 and RAA Schedule 6 and requested an effective date of July 22, 2015.

On December 17, 2014 in Docket No. ER15-643-000, PJM submitted revisions to various sections of the Tariff and the Operating Agreement, to incorporate changes related to how PJM determines the price of reserves it procures in the Real-Time Energy Market that exceed its normal real-time reserve requirements, and also how PJM allocates costs of reserves procured in the Day-ahead Energy Market that exceed its normal day-ahead reserve requirements ("ER15-643 Filing"). The proposed revisions included revisions to Attachment K-Appendix sections 1.3, 1.10, and 3.2, as well as the parallel provisions of Schedule 1 of the Operating Agreement. On February 11, 2015, PJM submitted its response to the Commission's January 27, 2015 deficiency notice seeking additional information regarding the ER15-643 Filing. On April

10, 2015, the Commission issued an order accepting the ER14-643 Filing effective March 1, 2015 as requested.

On December 31, 2014, in Docket No. ER15-806-000, PJM submitted ministerial revisions to definitions in the Tariff, Operating Agreement and RAA to conform the definitions across the PJM Governing Documents, including revisions to Definitions E-F of the Tariff ("ER15-806 Filing"). On February 19, 2015, the Commission issued an order accepting the ER15-806 Filing with an effective date of March 2, 2015.

On March 10, 2015, in Docket No. ER15-1213-000, PJM submitted revisions to Attachment Q of the PJM Tariff to incorporate several changes to its credit policy. PJM's revisions removed the Seller Credit provisions of Attachment Q because, as a result of changes that have been implemented in PJM's credit policy over the past several years, Seller Credit has become duplicative of other forms of Unsecured Credit and provides relatively limited utility to PJM's market and individual Participants ("ER15-1213 Filing"). On April 10, 2015, the Commission issued a letter order accepting the ER15-1213 Filing effective May 11, 2015.

On May 13, 2015, in Docket No. ER15-1703-000, PJM submitted revisions to Attachment K-Appendix of the Tariff, and the parallel provisions of Schedule 1 of the Operating Agreement, related to deadlines for posting Financial Transmission Right ("FTR") auction results. The proposed revisions allow for flexibility when circumstances beyond PJM's control prohibit PJM from posting auction results by the applicable deadline, and clarify that FTRs can be bilaterally traded for periods of time other than "monthly" periods ("ER15-1703 Filing"). On June 25, 2015, the Commission issued a letter order accepting the ER15-1703 Filing effective July 13, 2015.

On June 4, 2015, in Docket No. ER15-1849-000, PJM submitted revisions to the Tariff, Operating Agreement and RAA to improve the measurement and verification procedures for Curtailment Service Providers ("CSP") with residential customers providing demand response in the Day-ahead Energy Market, Real-time Energy Market, RPM capacity market and Synchronized Reserve market. ("ER15-1849 Filing"). The proposed revisions included revisions to Attachment DD.2, DD 5.12, DD 5.14, DD-1 of the Tariff, Definitions C-D of the Operating Agreement and Schedule 6 of the RAA. On July 23, 2015 the Commission issued a letter order accepting the ER15-1849 Filing effective August 3, 2015.

Finally, on June 23, 2015, in Docket No. ER15-1966-000, PJM submitted revisions to section 3.2 of Attachment K-Appendix of the Tariff and the identical provisions of section 3.2 of Schedule 1 of the Operating Agreement to revise the methodologies used to credit Market Sellers of certain types of generating units for Lost Opportunity Costs ("LOC") in PJM's Day-ahead Energy Market and Real-time Energy Market under specified circumstances. On August 31, 2015, the Commission issued an Order accepting the revisions with an effective date of September 1, 2015.

With the foregoing in mind, this ministerial filing is required to ensure that the aforementioned sections reflect the correct, Commission-accepted language. As described above, the ER15-623 Filing and the EL15-29 Filing were submitted prior to (though effective after) the ER15-643 Filing and the ER15-806 Filing, and therefore did not include the changes proposed in the ER15-643 Filing and ER15-806 Filing. Consequently, as of April 1, 2015, the affected sections (Definitions E-F of the Tariff in the ER15-806 Filing and the Attachment K-Appendix sections 1.3, 1.10 and 3.2 of the Tariff as well as the parallel sections of Schedule 1 of the Operating Agreement in the ER15-643 Filing) will not reflect the Commission-accepted revisions in the ER15-643 Filing and the ER15-806 Filing.

This ministerial filing is also required to ensure that Attachment Q properly reflects the Commission-accepted language in the ER15-623 Filing, the ER15-1213-000 Filing and the ER15-623-004 Compliance Filing as the dates of these filings and their effective dates overlap as well. This is also true for Attachment DD.2, DD5.12, DD5.14 and DD-1 of the Tariff, Definitions C-D of the Operating Agreement and Schedule 6 of the RAA. These sections were submitted in overlapping filings, namely ER15-623-000, ER15-1849-000, ER15-623-004, ER15-623-006 and ER15-623-008.

Additionally, while preparing the sections for this filing, a few ministerial corrections were found to be needed in Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA. The corrections are contained within Attachment A and are identified in a redline version marked as Attachment C. They were discovered when a comparison of the sections was run to ensure that the sections match.

Finally, there are a few sections in which language that was italicized to show as pending language from the ER15-623 Filing or the EL15-29 Filing can now be cleaned up to show as accepted language. The following sections can be cleaned up in this manner: Attachment K-Appendix section 5.2 of the Tariff and the parallel section in Schedule 1 of the Operating Agreement (as a result of the EL15-29-000 Filing and the ER15-1703 Filing); Attachment DD.2, DD 5.12, DD 5.14 and DD-1 of the Tariff, Definition C-D of the Operating Agreement and Schedule 6 of the RAA (as a result of the EL15-1849 Filing).

II. DESCRIPTION OF ENCLOSED TARIFF REVISIONS

To ensure that the aforementioned sections reflect all Commission-accepted language effective April 1, 2015, May 11, 2015, July 13, 2015 and August 3, 2015, PJM hereby submits the consolidated version of the sections as accepted in the aforementioned dockets. The revisions merely incorporate previously accepted language and do not make any substantive modifications to the sections of the Tariff, Operating Agreement and RAA.

III. WAIVER AND EFFECTIVE DATE

PJM requests an effective date of April 1, 2015 for the ministerial changes in Definitions E-F and Attachment K-Appendix sections 1.3, and 1.10 as well as the parallel sections of Schedule 1 of the Operating Agreement (sections 1.3 and 1.10). PJM requests an effective date of May 11, 2015 for the ministerial changes in Attachment Q of the Tariff and an effective date of July 13, 2015 for the ministerial changes in Attachment K-Appendix section 5.2 of the Tariff as well as the parallel section 5.2 of Schedule 1 of the Operating Agreement. PJM requests an effective date of August 3, 2015 for the ministerial revisions to Attachment DD.2, DD 5.12, DD 5.14 and DD-1 of the Tariff, Definitions C-D of the Operating Agreement and Schedule 6 of the RAA. Finally, PJM requests an effective date of September 1, 2015 for the ministerial revisions to Attachment K-Appendix section 3.2 of the Tariff as well as the parallel section 3.2 of Schedule 1 of the Operating Agreement. To permit such an effective date, PJM requests a waiver of the 60-days' notice requirement in section 35.3(a)(1) of the Commission's regulations. 18 C.F.R. § 35.3(a)(1). Good cause exists for such waiver because the amendments filed herein only incorporate language previously approved by the Commission, with the effective dates previously established by the Commission, and ensure that the current effective versions of those documents in the Commission's files and eTariff system and posted by PJM conform to and fully reflect the Commission's prior orders.

IV. DOCUMENTS ENCLOSED

Attachment A - a clean version of the Tariff, Operating Agreement and RAA sections.

Attachment B – a copy of the marked version of the revisions to the Tariff, Operating Agreement and RAA previously filed and approved by the Commission.

Attachment C – a copy of the redlines correcting OATT Attachment DD-1 and the parallel RAA Schedule 6.

V. CORRESPONDENCE AND COMMUNICATIONS

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VI. 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,[1] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[2] alerting them that this filing has been made by PJM and is

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

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

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,

Jennifer Tribulski
PJM Interconnection, L.L.C.

Attachment A

Sections of the
PJM Open Access Transmission Tariff,
PJM Operating Agreement and
PJM Reliability Assurance Agreement

(Clean Format)

Section(s) of the
PJM Open Access Transmission Tariff

(Clean Format)

Definitions – E - F

1.10A Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall have the same meaning provided in the Operating Agreement.

1.10B Economic Minimum:

The lowest incremental MW output level a unit can achieve while following economic dispatch.

1.11 Eligible Customer:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

1.11.01 Emergency Condition:

A condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

1.11A Energy Resource:

A generating facility that is not a Capacity Resource.

1.11A.01 Energy Settlement Area:

The bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

1.11B Energy Transmission Injection Rights:

The rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

1.11C Environmental Laws:

Applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

1.11D Existing Generation Capacity Resource:

Existing Generation Capacity Resource shall have the meaning specified in the Reliability Assurance Agreement.

1.12 Facilities Study:

An engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate an Interconnection Request or Upgrade Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Interconnection Facilities necessary to accommodate the New Service Customer's New Service Request in accordance with Section 207 of Part VI of the Tariff.

1.12A Federal Power Act:

The Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

1.12B FERC:

The Federal Energy Regulatory Commission or its successor.

1.13 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.13A Firm Transmission Withdrawal Rights:

The rights to schedule energy and capacity withdrawals from a Point of Interconnection (as defined in Section 1.33A) of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1.01 Additional Day-ahead Scheduling Reserves Requirement

"Additional Day-ahead Scheduling Reserves Requirement" shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.001 Base Day-ahead Scheduling Reserves Requirement

"Base Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.01A Cold Weather Alert.

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.02A Coordinated External Transaction.

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.02B Coordinated Transaction Scheduling.

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Section 1.13 of Schedule 1 of this Agreement.

1.3.1B.02C CTS Enabled Interface.

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"), designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45).

1.3.1B.02D CTS Interface Bid

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"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.

1.3.1E.01 Demand Bid

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

1.3.1E.02 Demand Bid Limit

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.03 Demand Bid Screening

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.04 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1F.01 Emergency Load Response Program

The Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2A.02 Economic Maximum.

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.2B.01 Extended Primary Reserve Requirement

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.2B.02 Extended Synchronized Reserve Requirement

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9.01 Hot Weather Alert.

"Hot Weather Alert" shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

1.3.9A Increment Offer.

"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.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

1.3.11.02 Load Management Event

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11A.01 Location.

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.13A Maximum Generation Emergency Alert.

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

“Offer Data” shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

“Office of the Interconnection Control Center” shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

“On-Site Generators” shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

“Operating Day” shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

“Operating Margin” shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

“Operating Margin Customer” shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.24A Pre-Emergency Load Response Program

The Pre-Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve.

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider.

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price.

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation.

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand.

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve.

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.29G Primary Reserve Requirement

"Primary Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2 (h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.01A Residual Metered Load.

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.001 Sub-meter.

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.02A Synchronized Reserve Requirement

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38.01 Up-to Congestion Transaction.

"Up-to Congestion Transaction" shall have the meaning specified in Section 1.10.1A of this Schedule.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.38B Virtual Transaction.

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone, when non-extraordinary conditions exist for the applicable twelve month period, as determined by PJM. If the lowest daily zonal peak load from the applicable twelve month period is abnormally low due to extraordinary conditions, as determined by PJM, Zonal Base Load shall mean the next lowest daily zonal peak load that was not affected by extraordinary conditions during the applicable twelve month period, increased by the projected load growth rate for the relevant Zone. For the purposes of this definition, extraordinary conditions shall mean a significant event, or combination of events, that affect the operation of the bulk power system in an atypical manner and results in an abnormal reduction in the consumption of energy within a Zone.

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 dynamically scheduled 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. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited 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.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. 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), 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, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, 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 hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all Generation Capacity Resources; and

ix) Shall not exceed an energy offer price of $1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00, for all Economic Load Response Resources;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, $1,100/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt 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. 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 per MWh 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 and no-load fees, 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 offer by a Market Seller of a Generation Capacity Resource 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 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. 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. The offer must equal or exceed 0.1 megawatts, and the offer 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. 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).

(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 MW 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, no-load 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.

(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 and no-load fees, 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 and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

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 or no-load fees.

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 dispatch 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 dispatch 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 any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. 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 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) *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.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

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

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

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer

in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

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

historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

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

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

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

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

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

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

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

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

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

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

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the applicable offer for energy on which the generating unit was committed in the Real-time Energy Market, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

The deviation of the generating unit's output is equal to the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

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

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

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit,

minus the sum of (C) the applicable offer for energy on which the generating unit was committed in the Day-ahead Energy Market, inclusive of no-load costs, plus (D) the start-up cost, divided by the hours committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

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

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

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

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

The deviation of the generating unit's output is equal to the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.
For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

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

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

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

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

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

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

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

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

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

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

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

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

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

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

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

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

where:

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

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit’s MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit’s MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

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

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

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

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

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

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

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

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

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

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

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

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual

reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

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

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of

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

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

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

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

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

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

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

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

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

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized

Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Synchronized Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

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

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

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

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

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

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Primary Reserve Requirement shall each be phased in as described below:

i. \$250/MWh for the 2012/2013 Delivery Year;

ii. \$400/MWh for the 2013/2014 Delivery Year;

iii. \$550/MWh for the 2014/2015 Delivery Year; and

iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

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

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

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

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

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

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

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

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

3.2.3B Reactive Services.

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

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

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

The deviation of the generating unit's output is equal to the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

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

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

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

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

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the

Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

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

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through

3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Offer and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right or had an Up-to Congestion Transaction that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for a path at or near the path of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Offer, Decrement Bid or Up-to Congestion Transaction is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated

using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an unanticipated event outside the control of PJM that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall

assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

ATTACHMENT Q

PJM CREDIT POLICY

POLICY STATEMENT:

It is the policy of PJM Interconnection, LLC ("PJM") that prior to an entity participating in the PJM Markets, or in order to take Transmission Service, the entity must demonstrate its ability to meet PJMSettlement's credit requirements.

Prior to becoming a Market Participant, Transmission Customer, and/or Member of PJM, PJMSettlement must accept and approve a Credit Application (including Credit Agreement) from such entity and establish a Working Credit Limit with PJMSettlement. PJMSettlement shall approve or deny an accepted Credit Application on the basis of a complete credit evaluation including, but not be limited to, a review of financial statements, rating agency reports, and other pertinent indicators of credit strength.

POLICY INTENT:

This credit policy describes requirements for: (1) the establishment and maintenance of credit by Market Participants, Transmission Customers, and entities seeking either such status (collectively "Participants"), pursuant to one or more of the Agreements, and (2) forms of security that will be deemed acceptable (hereinafter the "Financial Security") in the event that the Participant does not satisfy the financial or other requirements to establish Unsecured Credit.

This policy also sets forth the credit limitations that will be imposed on Participants in order to minimize the possibility of failure of payment for services rendered pursuant to the Agreements, and conditions that will be considered an event of default pursuant to this policy and the Agreements.

These credit rules may establish certain set-asides of credit for designated purposes (such as for FTR or RPM activity). Such set-asides shall be construed to be applicable to calculation of credit requirements only, and shall not restrict PJMSettlement's ability to apply such designated credit to any obligation(s) in case of a default.

PJMSettlement may post on PJM's web site, and may reference on OASIS, a supplementary document which contains additional business practices (such as algorithms for credit scoring) that are not included in this document. Changes to the supplementary document will be subject to stakeholder review and comment prior to implementation. PJMSettlement may specify a required compliance date, not less than 15 days from notification, by which time all Participants must comply with provisions that have been revised in the supplementary document.

APPLICABILITY:

This policy applies to all Participants.

IMPLEMENTATION:

I. CREDIT EVALUATION

Each Participant will be subject to a complete credit evaluation in order for PJMSettlement to determine creditworthiness and to establish an **Unsecured Credit Allowance**, if applicable; provided, however, that a Participant need not provide the information specified in section I.A or I.B if it notifies PJMSettlement in writing that it does not seek any Unsecured Credit Allowance. PJMSettlement will identify any necessary Financial Security requirements and establish a Working Credit Limit for each Participant. In addition, PJMSettlement will perform follow-up credit evaluations on at least an annual basis.

If a **Corporate Guaranty** is being utilized to establish credit for a Participant, the guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

PJMSettlement will provide a Participant, upon request, with a written explanation for any change in credit levels or collateral requirements. PJMSettlement will provide such explanation within ten Business Days.

If a Participant believes that either its level of unsecured credit or its collateral requirement has been incorrectly determined, according to this credit policy, then the Participant may send a request for reconsideration in writing to PJMSettlement. Such a request should include:

- A citation to the applicable section(s) of the PJMSettlement credit policy along with an explanation of how the respective provisions of the credit policy were not carried out in the determination as made

- A calculation of what the Participant believes should be the correct credit level or collateral requirement, according to terms of the credit policy

PJMSettlement will reconsider the determination and will provide a written response as promptly as practical, but no longer than ten Business Days of receipt of the request. If the Participant still feels that the determination is incorrect, then the Participant may contest that determination. Such contest should be in written form, addressed to PJMSettlement, and should contain:

♦ A complete copy of the Participant's earlier request for reconsideration, including citations and calculations

♦ A copy of PJMSettlement's written response to its request for reconsideration

♦ An explanation of why it believes that the determination still does not comply with the credit policy

PJMSettlement will investigate and will respond to the Participant with a final determination on the matter as promptly as practical, but no longer than 20 Business Days.

Neither requesting reconsideration nor contesting the determination following such request shall relieve or delay Participant's responsibility to comply with all provisions of this credit policy.

A. Initial Credit Evaluation

In completing the initial credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit with its application audited financial statements for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the Participant, if shorter. All financial and related information considered for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement.

The information should include, but not be limited to, the following:

a. If publicly traded:
   - i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
   - ii. Form 8-K reports disclosing Material changes, if any.

b. If privately held:
   - i. Management's Discussion & Analysis
   - ii. Report of Independent Accountants
   - iii. Financial Statements, including:
     - Balance Sheet
     - Income Statement
     - Statement of Cash Flows
     - Statement of Stockholder's Equity
   - iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) References

PJMSettlement may request Participants to provide with their applications at least one (1) bank and three (3) utility credit references. In the case where a Participant does not have the required utility references, trade payable vendor references may be substituted.

4) Litigation, Commitments and Contingencies

Each Participant is also required to provide with its application information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJMSettlement or are applying for membership with PJMSettlement. Each Participant is also required to disclose the existence of any ongoing investigations by the Securities and Exchange Commission ("SEC"), Federal Energy Regulatory Commission ("FERC"), Commodity Futures Trading Commission ("CFTC"), or any other governing, regulatory, or standards body. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

B. Ongoing Credit Evaluation

On at least an annual basis, PJMSettlement will perform follow-up credit evaluations on all Participants. In completing the credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit audited annual financial statements as soon as they become available and no later than 120 days after fiscal year end. Each Participant is also required to provide PJMSettlement with quarterly financial statements promptly upon their issuance, but no later than 60 days after the end of each quarter. All financial and related information considered

for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement. If financial statements are not provided within the timeframe required, the Participant may not be granted an Unsecured Credit Allowance.

The information should include, but not be limited to, the following:

a. If publicly traded:
    i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
    ii. Form 8-K reports disclosing Material changes, if any, immediately upon issuance.

b. If privately held:
    i. Management's Discussion & Analysis
    ii. Report of Independent Accountants
    iii. Financial Statements, including:
        - Balance Sheet
        - Income Statement
        - Statement of Cash Flows
        - Statement of Stockholder's Equity
    iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) Material Changes

Each Participant is responsible for informing PJMSettlement immediately, in writing, of any Material change in its financial condition. However, PJMSettlement may also independently establish from available information that a Participant has experienced a Material change in its financial condition without regard to whether such Participant has informed PJMSettlement of the same.

For the purpose of this policy, a Material change in financial condition may include, but not be limited to, any of the following:

a. a downgrade of any debt rating by any rating agency;
b. being placed on a credit watch with negative implications by any rating agency;
c. a bankruptcy filing;
d. insolvency;

e. a report of a quarterly or annual loss or a decline in earnings of ten percent or more compared to the prior period;
f. restatement of prior financial statements;
g. the resignation of key officer(s);
h. the filing of a lawsuit that could adversely impact any current or future financial results by ten percent or more;
i. financial default in another organized wholesale electric market futures exchange or clearing house;
j. revocation of a license or other authority by any Federal or State regulatory agency; where such license or authority is necessary or important to the Participants continued business for example, FERC market-based rate authority, or State license to serve retail load; or
k. a significant change in credit default spreads, market capitalization, or other market-based risk measurement criteria, such as a recent increase in Moody's KMV Expected Default Frequency (EDF^{tm}) that is noticeably greater than the increase in its peers' EDF^{tm} rates, or a collateral default swap (CDS) premium normally associated with an entity rated lower than investment grade.

If PJMSettlement determines that a Material change in the financial condition of the Participant has occurred, it may require the Participant to provide Financial Security within two Business Days, in an amount and form approved by PJMSettlement. If the Participant fails to provide the required Financial Security, the Participant shall be in default under this credit policy.

In the event that PJMSettlement determines that a Material change in the financial condition of a Participant warrants a requirement to provide Financial Security, PJMSettlement shall provide the Participant with a written explanation of why such determination was made. However, under no circumstances shall the requirement that a Participant provide the requisite Financial Security be deferred pending the issuance of such written explanation.

4) Litigation, Commitments, and Contingencies

Each Participant is also required to provide information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon initiation or change or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJM or are applying for membership within PJM. Each Participant is also required to disclose the existence of any ongoing investigations by the SEC, FERC, CFTC or any other governing, regulatory, or standards body. These disclosures shall be made upon initiation or change, or as requested by PJMSettlement.

C. Corporate Guaranty

If a Corporate Guaranty is being utilized to establish credit for a Participant, the Guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

An irrevocable and unconditional Corporate Guaranty may be utilized as part of the credit evaluation process, but will not be considered a form of Financial Security. The Corporate Guaranty will be considered a transfer of credit from the Guarantor to the Participant. The Corporate Guaranty must guarantee the (i) full and prompt payment of all amounts payable by the Participant under the Agreements, and (ii) performance by the Participant under this policy.

The Corporate Guaranty should clearly state the identities of the "Guarantor," "Beneficiary" (PJMSettlement) and "Obligor" (Participant). The Corporate Guaranty must be signed by an officer of the Guarantor, and must demonstrate that it is duly authorized in a manner acceptable to PJMSettlement. Such demonstration may include either a Corporate Seal on the Guaranty itself, or an accompanying executed and sealed Secretary's Certificate noting that the Guarantor was duly authorized to provide such Corporate Guaranty and that the person signing the Corporate Guaranty is duly authorized, or other manner acceptable to PJMSettlement.

A Participant supplying a Corporate Guaranty must provide the same information regarding the Guarantor as is required in the "Initial Credit Evaluation" §I.A. and the "Ongoing Evaluation" §I.B. of this policy, including providing the Rating Agency Reports, Financial Statements and Related Information, References, Litigation Commitments and Contingencies, and Other Disclosures. A Participant supplying a Foreign or Canadian Guaranty must also satisfy the requirements of §I.C.1 or §I.C.2, as appropriate.

If there is a Material change in the financial condition of the Guarantor or if the Corporate Guaranty comes within 30 days of expiring without renewal, the Participant will be required to provide Financial Security either in the form of a cash deposit or a letter of credit. Failure to provide the required Financial Security within two Business Days after request by PJMSettlement will constitute an event of default under this credit policy. A Participant may request PJMSettlement to perform a credit evaluation in order to determine creditworthiness and to establish an Unsecured Credit Allowance, if applicable. If PJMSettlement determines that a Participant does qualify for a sufficient Unsecured Credit Allowance, then Financial Security will not be required.

The PJMSettlement Credit Application contains an acceptable form of Corporate Guaranty that should be utilized by a Participant choosing to establish its credit with a Corporate Guaranty. If the Corporate Guaranty varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a Corporate Guaranty and meeting the policy provisions are the responsibility of the Participant.

1) Foreign Guaranties

A Foreign Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in a country other than the United States or Canada. The entity providing a Foreign Guaranty on behalf of a Participant is a Foreign Guarantor. A Participant may provide a Foreign

Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met:

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Foreign Guaranty at any time, including for material adverse circumstances or occurrences.

a. A Foreign Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.
   iv. Will not be accepted towards a Participant's Unsecured Credit Allowance for more than the following limits, depending on the Foreign Guarantor's credit rating:

Rating of Foreign Guarantor	Maximum Accepted Guaranty if Country Rating is AAA	Maximum Accepted Guaranty if Country Rating is AA+
A- and above	USD50,000,000	USD30,000,000
BBB+	USD30,000,000	USD20,000,000
BBB	USD10,000,000	USD10,000,000
BBB- or below	USD 0	USD 0

   v. May not exceed 50% of the Participant's total credit, if the Foreign Grantor is rated less than BBB+.

b. A Foreign Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Foreign Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must have a Senior Unsecured (or equivalent, in PJMSettlement's sole discretion) rating of BBB (one notch above BBB-) or greater by any and all agencies that provide rating coverage of the entity.
   vi. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance

vii. Must provide a Secretary's Certificate certifying the adoption of Corporate Resolutions:
    1. Authorizing and approving the Guaranty; and
    2. Authorizing the Officers to execute and deliver the Guaranty on behalf of the Guarantor.

viii. Must be domiciled in a country with a minimum long-term sovereign (or equivalent) rating of AA+/Aa1, with the following conditions:
    1. Sovereign ratings must be available from at least two rating agencies acceptable to PJMSettlement (e.g. S&P, Moody's, Fitch, DBRS).
    2. Each agency's sovereign rating for the domicile will be considered to be the lowest of: country ceiling, senior unsecured government debt, long-term foreign currency sovereign rating, long-term local currency sovereign rating, or other equivalent measures, at PJMSettlement's sole discretion.
    3. Whether ratings are available from two or three agencies, the lowest of the two or three will be used.

ix. Must be domiciled in a country that recognizes and enforces judgments of US courts.

x. Must demonstrate financial commitment to activity in the United States as evidenced by one of the following:
    1. American Depository Receipts (ADR) are traded on the New York Stock Exchange, American Stock Exchange, or NASDAQ.
    2. Equity ownership worth over USD100,000,000 in the wholly-owned or majority owned subsidiaries in the United States.

xi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this credit policy.

xii. Must pay for all expenses incurred by PJMSettlement related to reviewing and accepting a foreign guaranty beyond nominal in-house credit and legal review.

xiii. Must, at its own cost, provide PJMSettlement with independent legal opinion from an attorney/solicitor of PJMSettlement's choosing and licensed to practice law in the United States and/or Guarantor's domicile, in form and substance acceptable to PJMSettlement in its sole discretion, confirming the enforceability of the Foreign Guaranty, the Guarantor's legal authorization to grant the Guaranty, the conformance of the Guaranty, Guarantor, and Guarantor's domicile to all of these requirements, and such other matters as PJMSettlement may require in its sole discretion.

2) Canadian Guaranties

A Canadian Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in Canada and satisfies all of the provisions below. The entity providing a Canadian Guaranty on behalf of a Participant is a Canadian Guarantor. A Participant may provide a Canadian Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met.

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Canadian Guaranty at any time for reasonable cause, including adverse material circumstances.

a. A Canadian Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.

b. A Canadian Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Canadian Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance.

   vi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Credit Policy.

Ia. MINIMUM PARTICIPATION REQUIREMENTS

A. PJM Market Participation Eligibility Requirements

To be eligible to transact in PJM Markets, a Market Participant must demonstrate in accordance with the Risk Management and Verification processes set forth below that it qualifies in one of the following ways:

1. an "appropriate person," as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act, or;

2. an "eligible contract participant," as that term is defined in Section 1a(18), or successor provision, of the Commodity Exchange Act, or;

3. a business entity or person who is in the business of: (1) generating, transmitting, or distributing electric energy, or (2) providing electric energy services that are necessary to support the reliable operation of the transmission system, or;

4. a Market Participant seeking eligibility as an "appropriate person" providing an unlimited Corporate Guaranty in a form acceptable to PJMSettlement as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty, or;

5. a Market Participant providing a letter of credit of at least $5 million to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJMSettlement.

If, at any time, a Market Participant cannot meet the eligibility requirements set forth above, it shall immediately notify PJMSettlement and immediately cease conducting transactions in the PJM Markets. PJMSettlement shall terminate a Market Participant's transaction rights in the PJM Markets if, at any time, it becomes aware that the Market Participant does not meet the minimum eligibility requirements set forth above.

In the event that a Market Participant is no longer able to demonstrate it meets the minimum eligibility requirements set forth above, and possesses, obtains or has rights to possess or obtain, any open or forward positions in PJM's Markets, PJMSettlement may take any such action it deems necessary with respect to such open or forward positions, including, but not limited to, liquidation, transfer, assignment or sale; provided, however, that the Market Participant will, notwithstanding its ineligibility to participate in the PJM Markets, be entitled to any positive market value of those positions, net of any obligations due and owing to PJM and/or PJMSettlement.

B. Risk Management and Verification

All Participants shall provide to PJMSettlement an executed copy of the annual certification set forth in Appendix 1 to this Attachment Q. This certification shall be provided before an entity is eligible to participate in the PJM Markets and shall be initially submitted to PJMSettlement together with the entity's Credit Application. Thereafter, it shall be submitted each calendar year by all Participants during a period beginning on January 1 and ending April 30, except that new Participants who became eligible to participate in PJM markets during the period of January through April shall not be required to resubmit such certification until the following calendar year. Except for certain FTR Participants (discussed below) or in cases of manifest error, PJMSettlement will accept such certifications as a matter of course and Participants will not need further notice from PJMSettlement before commencing or maintaining their eligibility to participate in PJM markets. A Participant that fails to provide its annual certification by April 30 shall be ineligible to transact in the PJM markets and PJM will disable the Participant's access to the PJM markets until such time as PJMSettlement receives the Participant's certification.

Participants acknowledge and understand that the annual certification constitutes a representation upon which PJMSettlement will rely. Such representation is additionally made under the PJM Tariff, filed with and accepted by FERC, and any inaccurate or incomplete statement may subject the Participant to action by FERC. Failure to comply with any of the criteria or

requirements listed herein or in the certification may result in suspension of a Participant's transaction rights in the PJM markets.

Certain FTR Participants (those providing representations found in paragraph 3.b of the annual certification set forth in Appendix 1 to this Attachment Q) are additionally required to submit to PJMSettlement (at the time they make their annual certification) a copy of their current governing risk control policies, procedures and controls applicable to their FTR trading activities, except that if no substantive changes have been made to such policies, practices and/or controls applicable to their FTR trading activities, they may instead submit to PJMSettlement a certification stating that no changes have been made. PJMSettlement will review such documentation to verify that it appears generally to conform to prudent risk management practices for entities trading in FTR-type markets. If principles or best practices relating to risk management in FTR-type markets are published, as may be modified from time to time, by a third-party industry association, such as the Committee of Chief Risk Officers, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the fundamental sufficiency of the FTR Participant's risk controls. Those FTR Participants subject to this provision shall make a one-time payment of $1,000.00 to PJMSettlement to cover costs associated with review and verification. Thereafter, if such FTR Participant's risk policies, procedures and controls applicable to its FTR trading activities change substantively, it shall submit such modified documentation, without charge, to PJMSettlement for review and verification at the time it makes its annual certification. Such FTR Participant's continued eligibility to participate in the PJM FTR markets is conditioned on PJMSettlement notifying such FTR Participant that its annual certification, including the submission of its risk policies, procedures and controls, has been accepted by PJMSettlement. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph, however, in all circumstances, PJMSettlement and any third-party it may retain will treat as confidential the documentation provided by an FTR Participant under this paragraph, consistent with the applicable provisions of PJM's Operating Agreement.

An FTR Participant that makes the representation in paragraph 3.a of the annual certification understand that PJMSettlement, given the visibility it has over a Participant's overall market activity in performing billing and settlement functions, may at any time request the FTR Participant provide additional information demonstrating that it is in fact eligible to make the representation in paragraph 3.a of the annual certification. If such additional information is not provided or does not, in PJMSettlement's judgment, demonstrate eligibility to make the representation in paragraph 3.a of the annual certification, PJMSettlement will require the FTR Participant to instead make the representations required in paragraph 3.b of the annual certification, including representing that it has submitted a copy of its current governing risk control policies, procedures and controls applicable to its FTR trading activities. If the FTR Participant cannot or does not make those representations as required in paragraph 3.b of the annual certification, then PJM will terminate the FTR Participant's rights to purchase FTRs in the FTR market and may terminate the FTR Participant's rights to sell FTRs in the PJM FTR market.

PJMSettlement shall also conduct a periodic compliance verification process to review and verify, as applicable, Participants' risk management policies, practices, and procedures pertaining to the Participants' activities in the PJM markets. Such review shall include verification that:

1. The risk management framework is documented in a risk policy addressing market, credit and liquidity risks.
2. The Participant maintains an organizational structure with clearly defined roles and responsibilities that clearly segregates trading and risk management functions.
3. There is clarity of authority specifying the types of transactions into which traders are allowed to enter.
4. The Participant has requirements that traders have adequate training relative to their authority in the systems and PJM markets in which they transact.
5. As appropriate, risk limits are in place to control risk exposures.
6. Reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization.
7. Processes are in place for qualified independent review of trading activities.
8. As appropriate, there is periodic valuation or mark-to-market of risk positions.

If principles or best practices relating to risk management in PJM-type markets are published, as may be modified from time to time, by a third-party industry association, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the sufficiency of the Participant's risk controls. PJMSettlement may select Participants for review on a random basis and/or based on identified risk factors such as, but not limited to, the PJM markets in which the Participant is transacting, the magnitude of the Participant's transactions in the PJM markets, or the volume of the Participant's open positions in the PJM markets. Those Participants notified by PJMSettlement that they have been selected for review shall, upon 14 calendar days notice, provide a copy of their current governing risk control policies, procedures and controls applicable to their PJM market activities and shall also provide such further information or documentation pertaining to the Participants' activities in the PJM markets as PJMSettlement may reasonably request. Participants selected for risk management verification through a random process and satisfactorily verified by PJMSettlement shall be excluded from such verification process based on a random selection for the subsequent two years. PJMSettlement shall annually randomly select for review no more than 20% of the Participants in each member sector.

Each selected Participant's continued eligibility to participate in the PJM markets is conditioned upon PJMSettlement notifying the Participant of successful completion of PJMSettlement's verification of the Participant's risk management policies, practices and procedures, as discussed

herein. However, if PJMSettlement notifies the Participant in writing that it could not successfully complete the verification process, PJMSettlement shall allow such Participant 14 calendar days to provide sufficient evidence for verification prior to declaring the Participant as ineligible to continue to participate in PJM's markets, which declaration shall be in writing with an explanation of why PJMSettlement could not complete the verification. If, prior to the expiration of such 14 calendar days, the Participant demonstrates to PJMSettlement that it has filed with the Federal Energy Regulatory Commission an appeal of PJMSettlement's risk management verification determination, then the Participant shall retain its transaction rights, pending the Commission's determination on the Participant's appeal. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph. PJMSettlement and any third party it may retain will treat as confidential the documentation provided by a Participant under this paragraph, consistent with the applicable provisions of the Operating Agreement. If PJMSettlement retains such outside expertise, a Participant may direct in writing that PJMSettlement perform the risk management review and verification for such Participant instead of utilizing a third party, provided however, that employees and contract employees of PJMSettlement and PJM shall not be considered to be such outside expertise or third parties.

Participants are solely responsible for the positions they take and the obligations they assume in PJM markets. PJMSettlement hereby disclaims any and all responsibility to any Participant or PJM Member associated with Participant's submitting or failure to submit its annual certification or PJMSettlement's review and verification of an FTR Participant's risk policies, procedures and controls. Such review and verification is limited to demonstrating basic compliance by an FTR Participant with the representation it makes under paragraph 3.b of its annual certification showing the existence of written policies, procedures and controls to limit its risk in PJM's FTR markets and does not constitute an endorsement of the efficacy of such policies, procedures or controls.

C. Capitalization

In addition to the Annual Certification requirements in Appendix 1 to this Attachment Q, a Participant must demonstrate that it meets the minimum financial requirements appropriate for the PJM market(s) in which it transacts by satisfying either the Minimum Capitalization or the Provision of Collateral requirements listed below:

1. Minimum Capitalization

FTR Participants must demonstrate a tangible net worth in excess of $1 million or tangible assets in excess of $10 million. Other Participants must demonstrate a tangible net worth in excess of $500,000 or tangible assets in excess of $5 million.

a. In either case, consideration of "tangible" assets and net worth shall exclude assets (net of any matching liabilities, assuming the result is a positive value) which PJMSettlement reasonably believes to be restricted, highly risky, or potentially unavailable to settle a claim in the event of default. Examples include, but are not

limited to, restricted assets and Affiliate assets, derivative assets, goodwill, and other intangible assets.

b. Demonstration of “tangible” assets and net worth may be satisfied through presentation of an acceptable Corporate Guaranty, provided that both:

(i) the guarantor is an affiliate company that satisfies the tangible net worth or tangible assets requirements herein, and;

(ii) the Corporate Guaranty is either unlimited or at least $500,000.

If the Corporate Guaranty presented by the Participant to satisfy these Capitalization requirements is limited in value, then the Participant’s resulting Unsecured Credit Allowance shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this Credit Policy, or:

(2) the face value of the Corporate Guaranty, reduced by $500,000 and further reduced by 10%. (For example, a $10.5 million Corporate Guaranty would be reduced first by $500,000 to $10 million and then further reduced 10% more to $9 million. The resulting $9 million would be the Participant’s Unsecured Credit Allowance available through the Corporate Guaranty).

In the event that a Participant provides collateral in addition to a limited Corporate Guaranty to increase its available credit, the value of such collateral shall be reduced by 10%. This reduced value shall be deemed Financial Security and available to satisfy the requirements of this Credit Policy.

Demonstrations of capitalization must be presented in the form of audited financial statements for the Participant’s most recent fiscal year.

2. Provision of Collateral

If a Participant does not demonstrate compliance with its applicable Minimum Capitalization Requirements above, it may still qualify to participate in PJM’s markets by posting additional collateral, subject to the terms and conditions set forth herein.

Any collateral provided by a Participant unable to satisfy the Minimum Capitalization Requirements above will be restricted in the following manner:

i. Collateral provided by FTR Participants shall be reduced by $500,000 and then further reduced by 10%. This reduced amount shall be considered the Financial Security provided by the Participant and available to satisfy requirements of this Credit Policy.

ii. Collateral provided by other Participants that engage in Virtual Transactions or Export Transactions shall be reduced by $200,000 and then further reduced by 10%. This reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

iii. Collateral provided by other Participants that do not engage in Virtual Transactions or Export Transactions shall be reduced by 10%, and this reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

In the event a Participant that satisfies the Minimum Participation Requirements through provision of collateral also provides a Corporate Guaranty to increase its available credit, then the Participant's resulting Unsecured Credit Allowance conveyed through such Guaranty shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this credit policy, or,

(2) the face value of the Guaranty, reduced by 10%.

II. CREDIT ALLOWANCE AND WORKING CREDIT LIMIT

PJMSettlement's credit evaluation process will include calculating a Credit Score for each Participant. The credit score will be utilized to determine a Participant's Unsecured Credit Allowance.

Participants who do not qualify for an Unsecured Credit Allowance will be required to provide Financial Security based on their Peak Market Activity, as provided below.

A corresponding Working Credit Limit will be established based on the Unsecured Credit Allowance and/or the Financial Security provided.

Where Participant of PJM are considered Affiliates, Unsecured Credit Allowances and Working Credit Limits will be established for each individual Participant, subject to an aggregate maximum amount for all Affiliates as provided for in §II.F of this policy.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

A. Credit Score

For participants with credit ratings, a Credit Score will be assigned based on their senior unsecured credit rating and credit watch status as shown in the table below. If an explicit senior unsecured rating is not available, PJMSettlement may impute an equivalent rating from other ratings that are available. For Participants without a credit rating, but who wish to be considered for unsecured Credit, a Credit Score will be generated from PJMSettlement's review and analysis of various factors that are predictors of financial strength and creditworthiness. Key factors in the scoring process include, financial ratios, and years in business. PJMSettlement will consistently apply the measures it uses in determining Credit Scores. The credit scoring methodology details are included in a supplementary document available on OASIS.

Rated Entities Credit Scores

Rating	Score	Score Modifier	
		Credit Watch Negative	Credit Watch Positive
AAA	100	-1.0	0.0
AA+	99	-1.0	0.0
AA	99	-1.0	0.0
AA-	98	-1.0	0.0
A+	97	-1.0	0.0
A	96	-2.0	0.0
A-	93	-3.0	1.0
BBB+	88	-4.0	2.0
BBB	78	-4.0	2.0
BBB-	65	-4.0	2.0
BB+ and below	0	0.0	0.0

B. Unsecured Credit Allowance

PJMSettlement will determine a Participant's Unsecured Credit Allowance based on its Credit Score and the parameters in the table below. The maximum Unsecured Credit Allowance is the lower of:

1) A percentage of the Participant's Tangible Net Worth, as stated in the table below, with the percentage based on the Participant's credit score; and

2) A dollar cap based on the credit score, as stated in the table below:

Credit Score	Tangible Net Worth Factor	Maximum Unsecured Credit Allowance ($ Million)
91-100	2.125 – 2.50%	$50
81-90	1.708 – 2.083%	$42
71-80	1.292 – 1.667%	$33
61-70	0.875 – 1.25%	$7
51-60	0.458 – 0.833%	$0-$2
50 and Under	0%	$0

If a Corporate Guaranty is utilized to establish an Unsecured Credit Allowance for a Participant, the value of a Corporate Guaranty will be the lesser of:

- The limit imposed in the Corporate Guaranty;
- The Unsecured Credit Allowance calculated for the Guarantor; and
- A portion of the Unsecured Credit Allowance calculated for the Guarantor in the case of Affiliated Participants.

PJMSettlement has the right at any time to modify any Unsecured Credit Allowance and/or require additional Financial Security as may be deemed reasonably necessary to support current market activity. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.

PJMSettlement will maintain a posting of each Participant's unsecured Credit Allowance, along with certain other credit related parameters, on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

C. Peak Market Activity and Financial Security Requirement

A PJM Participant or Applicant that has an insufficient Unsecured Credit Allowance to satisfy its Peak Market Activity will be required to provide Financial Security such that its Unsecured Credit Allowance and Financial Security together are equal to its Peak Market Activity in order to secure its transactional activity in the PJM Market.

Peak Market Activity for Participants will be determined semi-annually beginning in the first complete billing week in the months of April and October. Peak Market Activity shall be the greater of the initial Peak Market Activity, as explained below, or the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two, or three week period, ending within a respective semi-annual period. However, Peak Market Activity shall not exceed the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two or three week period in the prior 52 weeks.

Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

The initial Peak Market Activity for Applicants will be determined by PJMSettlement based on a review of an estimate of their transactional activity for all PJM markets and services over the next 52 weeks, which the Applicant shall provide to PJMSettlement.

The initial Peak Market Activity for Participants, calculated at the beginning of each respective semi-annual period, shall be the three-week average of all non-zero invoice totals over the previous 52 weeks. This calculation shall be performed and applied within three business days following the day the invoice is issued for the first full billing week in the current semi-annual period.

Prepayments shall not affect Peak Market Activity unless otherwise agreed to in writing pursuant to this Credit Policy.

All Peak Market Activity calculations shall take into account reductions of invoice values effectuated by early payments which are applied to reduce a Participant's Peak Market Activity as contemplated by other terms of the Credit Policy; provided that the initial Peak Market Activity shall not be less than the average value calculated using the weeks for which no early payment was made.

A Participant may reduce its Financial Security Requirement by agreeing in writing (in a form acceptable to PJMSettlement) to make additional payments, including prepayments, as and when necessary to ensure that such Participant's Total Net Obligation at no time exceeds such reduced Financial Security Requirement.

PJMSettlement may, at its discretion, adjust a Participant's Financial Security Requirement if PJMSettlement determines that the Peak Market Activity is not representative of such Participant's expected activity, as a consequence of known, measurable, and sustained changes. Such changes may include the loss (without replacement) of short-term load contracts, when such contracts had terms of three months or more and were acquired through state-sponsored retail load programs, but shall not include short-term buying and selling activities.

PJMSettlement may waive the Financial Security Requirement for a Participant that agrees in writing that it shall not, after the date of such agreement, incur obligations under any of the Agreements. Such entity's access to all electronic transaction systems administered by PJM shall be terminated.

PJMSettlement will maintain a posting of each Participant's Financial Security Requirement on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

D. Working Credit Limit

PJMSettlement will establish a Working Credit Limit for each Participant against which its **Total Net Obligation** will be monitored. The Working Credit Limit is defined as 75% of the Financial Security provided to PJMSettlement and/or 75% of the Unsecured Credit Allowance determined by PJMSettlement based on a credit evaluation, as reduced by any applicable credit requirement determinants defined in this policy. A Participant's Total Net Obligation should not exceed its Working Credit Limit.

> Example: After a credit evaluation by PJMSettlement, a Participant is deemed able to support an Unsecured Credit Allowance of $10.0 million. The Participant will be assigned a Working Credit Limit of $8.5 million. PJMSettlement will monitor the Participant's Total Net Obligations against the Working Credit Limit.

A Participant with an Unsecured Credit Allowance may choose to provide Financial Security in order to increase its Working Credit Limit. A Participant with no Unsecured Credit Allowance may also choose to increase its Working Credit Limit by providing Financial Security in an amount greater than its Peak Market Activity.

If a Participant's Total Net Obligation approaches its Working Credit Limit, PJMSettlement may require the Participant to make an advance payment or increase its Financial Security in order to maintain its Total Net Obligation below its Working Credit Limit. Except as explicitly provided below, advance payments shall not serve to reduce the Participant's Peak Market Activity for the purpose of calculating credit requirements.

> Example: After 10 days, and with 5 days remaining before the bill is due to be paid, a Participant approaches its $4.0 million Working Credit Limit. PJMSettlement may require a prepayment of $2.0 million in order that the Total Net Obligation will not exceed the Working Credit Limit.

If a Participant exceeds its Working Credit Limit or is required to make advance payments more than ten times during a 52-week period, PJMSettlement may require Financial Security in an amount as may be deemed reasonably necessary to support its Total Net Obligation.

A Participant receiving unsecured credit may make early payments up to ten times in a rolling 52-week period in order to reduce its Peak Market Activity for credit requirement purposes. Imputed Peak Market Activity reductions for credit purposes will be applied to the billing period for which the payment was received. Payments used as the basis for such reductions must be received prior to issuance or posting of the invoice for the relevant billing period. The imputed Peak Market Activity reduction attributed to any payment may not exceed the amount of Unsecured Credit for which the Participant is eligible.

E. Credit Limit Setting For Affiliates

If two or more Participants are Affiliates and each is being granted an Unsecured Credit Allowance and a corresponding Working Credit Limit, PJMSettlement will consider the overall creditworthiness of the Affiliated Participants when determining the Unsecured Credit Allowances and Working Credit Limits in order not to grant more Unsecured Credit than the overall corporation could support.

Example: Participants A and B each have a $10.0 million Corporate Guaranty from their common parent, a holding company with an Unsecured Credit Allowance calculation of $12.0 million. PJMSettlement may limit the Unsecured Credit Allowance for each Participant to $6.0 million, so the total Unsecured Credit Allowance does not exceed the corporate total of $12.0 million.

PJMSettlement will work with Affiliated Participants to allocate the total Unsecured Credit Allowance among the Affiliates while assuring that no individual Participant, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. The aggregate Unsecured Credit for a Participant, including Unsecured Credit Allowance granted based on its own creditworthiness and any Unsecured Credit Allowance conveyed through a Guaranty shall not exceed $50 million. The aggregate Unsecured Credit for a group of Affiliates shall not exceed $50 million. A group of Affiliates subject to this cap shall request PJMSettlement to allocate the maximum Unsecured Credit and Working Credit Limit amongst the group, assuring that no individual Participant or common guarantor, shall exceed the Unsecured Credit level appropriate for its credit strength and activity.

F. Working Credit Limit Violations

1) Notification

A Participant is subject to notification when its Total Net Obligation to PJMSettlement approaches the Participant's established Working Credit Limit.

2) Suspension

A Participant that exceeds its Working Credit Limit is subject to suspension from participation in the PJM markets and from scheduling any future Transmission Service unless and until Participant's credit standing is brought within acceptable limits. A Participant will have two Business Days from notification to remedy the situation in a manner deemed acceptable by PJMSettlement. Additionally, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant's ongoing Transmission Service and participation in PJM Markets. Failure to comply with this policy will be considered an event of default under this credit policy.

G. PJM Administrative Charges

Financial Security held by PJMSettlement shall also secure obligations to PJM for PJM administrative charges.

H. Pre-existing Financial Security

PJMSettlement's credit requirements are applicable as of the effective date of the filing on May 5, 2010 by PJM and PJMSettlement of amendments to Attachment Q. Financial Security held by

PJM prior to the effective date of such amendments shall be held by PJM for the benefit of PJMSettlement.

III. VIRTUAL TRANSACTION SCREENING

A. Credit and Financial Security

PJMSettlement does not require a Market Participant to establish separate or additional credit for submitting Virtual Transactions. If a Market Participant chooses to establish additional Financial Security and/or Unsecured Credit Allowance in order to increase its Credit Available for Virtual Transactions, the Market Participant's Working Credit Limit for Virtual Transactions shall be increased in accordance with the definition therof. The Financial Security and/or Unsecured Credit Allowance available to increase a Market Participant's Credit Available for Virtual Transactions shall be the amount of Financial Security and/or Unsecured Credit Allowance available after subtracting any credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy, as applicable.

If a Market Participant chooses to provide additional Financial Security in order to increase its **Credit Available for Virtual Transactions PJMSettlement** may establish a reasonable timeframe, not to exceed three months, for which such Financial Security must be maintained. PJMSettlement will not impose such restriction on a deposit unless a Market Participant is notified prior to making the deposit. Such restriction, if applied, shall be applied to all future deposits by all Market Participants engaging in Virtual Transactions.

A Market Participant wishing to increase its Credit Available for Virtual Transactions by providing additional Financial Security may make the appropriate arrangements with PJMSettlement. PJMSettlement will make a good faith effort to make new Financial Security available as Credit Available for Virtual Transactions as soon as practicable after confirmation of receipt. In any event, however, Financial Security received and confirmed by noon on a business day will be applied (as provided under this policy) to Credit Available for Virtual Transactions no later than 10:00 am on the following business day. Receipt and acceptance of wired funds for cash deposit shall mean actual receipt by PJMSettlement's bank, deposit into PJMSettlement's customer deposit account, and confirmation by PJMSettlement that such wire has been received and deposited. Receipt and acceptance of letters of credit shall mean receipt of the original letter of credit or amendment thereto, and confirmation from PJMSettlement's credit and legal staffs that such letter of credit or amendment thereto conforms to PJMSettlement's requirements, which confirmation shall be made in a reasonable and practicable timeframe. To facilitate this process, bidders wiring funds for the purpose of increasing their Credit Available for Virtual Transactions are advised to specifically notify PJMSettlement that a wire is being sent for such purpose.

B. Virtual Transaction Screening Process

All Virtual Transactions submitted to PJM shall be subject to a credit screen prior to acceptance in the Day-ahead Energy Market auction. The credit screen process will automatically reject

Virtual Transactions submitted by the PJM market participant if the participant's Credit Available for Virtual Transactions is exceeded by the **Virtual Credit Exposure** that is calculated based on the participant's submitted Virtual Transactions as described below.

A Participant's Virtual Credit Exposure will be calculated on a daily basis for all Virtual Transactions submitted by the market participant for the next market day using the following equation:

Virtual Credit Exposure = INC and DEC Exposure + Up-to Congestion Exposure
Where:

1) INC and DEC Exposure is calculated as:

(a) ((the total MWh bid or offered, whichever is greater, hourly at each node) x the Nodal Reference Price x 1 day) summed over all nodes and all hours; plus (b) ((the difference between the total bid MWh cleared and total offered MWh cleared hourly at each node) x Nodal Reference Price) summed over all nodes and all hours for the previous cleared Day-ahead Energy Market.

2) Up-to Congestion Exposure is calculated as:

(a) Total MWh bid hourly for each Up-to Congestion Transaction x (price bid – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours; plus (b) Total MWh cleared hourly for each Up-to Congestion Transaction x (cleared price – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours for the previous cleared Day-ahead Energy Market, provided that hours for which the calculation for an Up-to Congestion Transaction is negative, it shall be deemed to have a zero contribution to the sum.

If a Market Participant's Virtual Transactions are rejected as a result of the credit screen process, the Market Participant will be notified via an eMKT error message. A Market Participant whose Virtual Transactions are rejected may alter its Virtual Transactions so that its Virtual Credit Exposure does not exceed its Credit Available forVirtual Transactions, and may resubmit them. Virtual Transactions may be submitted in one or more groups during a day. If one or more groups of Virtual Transactions is submitted and accepted, and a subsequent group of submitted Virtual Transactions causes the total submitted Virtual Transactions to exceed the Virtual Credit Exposure, then only that subsequent set of Virtual Transactions will be rejected. Previously accepted Virtual Transactions will not be affected, though the Market Participant may choose to withdraw them voluntarily.

IV. RELIABILITY PRICING MODEL AUCTION AND PRICE RESPONSIVE DEMAND CREDIT REQUIREMENTS

Settlement during any Delivery Year of cleared positions resulting or expected to result from any Reliability Pricing Model Auction shall be included as appropriate in Peak Market Activity, and the provisions of this Attachment Q shall apply to any such activity and obligations arising therefrom. In addition, the provisions of this section shall apply to any entity seeking to participate in any RPM Auction, to address credit risks unique to such auctions. The provisions of this section also shall apply under certain circumstances to PRD Providers that seek to commit Price Responsive Demand pursuant to the provisions of the Reliability Assurance Agreement.

A. Applicability

A Market Seller seeking to submit a Sell Offer in any Reliability Pricing Model Auction based on any Capacity Resource for which there is a materially increased risk of nonperformance must satisfy the credit requirement specified in section IV.B before submitting such Sell Offer. A PRD Provider seeking to commit Price Responsive Demand for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before it may commit the Price Responsive Demand. Credit must be maintained until such risk of non-performance is substantially eliminated, but may be reduced commensurate with the reduction in such risk, as set forth in Section IV.C.

For purposes of this provision, a resource for which there is a materially increased risk of nonperformance shall mean: (i) a Planned Generation Capacity Resource; (ii) a Planned Demand Resource or an Energy Efficiency Resource; (iii) a Qualifying Transmission Upgrade; (iv) an existing or Planned Generation Capacity Resource located outside the PJM Region that at the time it is submitted in a Sell Offer has not secured firm transmission service to the border of the PJM Region sufficient to satisfy the deliverability requirements of the Reliability Assurance Agreement; or (v) Price Responsive Demand to the extent the responsible PRD Provider has not registered PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

B. Reliability Pricing Model Auction and Price Responsive Demand Credit Requirement

Except as provided for Credit-Limited Offers below, for any resource specified in Section IV.A, other than Price Responsive Demand, the credit requirement shall be the RPM Auction Credit Rate, as provided in Section IV.D, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction. For Qualified Transmission Upgrades, the credit requirements shall be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit. However, the credit requirement for Planned Financed Generation Capacity Resources and Planned External Financed Generation Capacity Resources shall be one half of the product of the RPM Auction Credit Rate, as provided in Section IV.D, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction. The RPM Auction Credit Requirement for each Market Seller shall be the sum of the credit requirements for all such resources to be offered by such Market Seller in the auction or, as applicable, cleared by such Market Seller from the relevant auctions. For Price Responsive Demand specified in section IV.A, the credit requirement shall be based on the Nominal PRD Value (stated in Unforced Capacity terms) times the Price Responsive Demand Credit Rate as set forth in section IV.E.

Except for Credit-Limited Offers, the RPM Auction Credit Requirement for a Market Seller will be reduced for any Delivery Year to the extent less than all of such Market Seller's offers clear in the Base Residual Auction or any Incremental Auction for such Delivery Year. Such reduction shall be proportional to the quantity, in megawatts, that failed to clear in such Delivery Year.

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Seller electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement, in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the Auction Credit Rate resulting from section IV.D.b.; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Seller electing this alternative, the RPM Auction Credit Requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-Limited Offer, and the RPM Auction Credit Requirement subsequent to posting of the results will be the Auction Credit Rate, as provided in Section IV.D.b, c. or d., as applicable, times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The availability and operational details of Credit-Limited Offers shall be as described in the PJM Manuals.

As set forth in Section IV.D, a Market Seller's Auction Credit Requirement shall be determined separately for each Delivery Year.

C. Reduction in Credit Requirement

As specified in Section IV.D, the RPM Auction Credit Rate may be reduced under certain circumstances after the auction has closed.

The Price Responsive Demand credit requirement shall be reduced as and to the extent the PRD Provider registers PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

In addition, the RPM Auction Credit Requirement for a Participant for any given Delivery Year shall be reduced periodically, provided the Participant successfully meets progress milestones that reduce the risk of non-performance, as follows:

a. For Planned Demand Resources and Energy Efficiency Resources, the RPM Auction Credit Requirement will be reduced in direct proportion to the megawatts of such Demand Resource that the Resource Provider qualifies as a Capacity Resource, in accordance with the procedures established under the Reliability Assurance Agreement.

b. For Existing Generation Capacity Resources located outside the PJM Region that have not secured sufficient firm transmission to the border of the PJM Region prior to the auction in which such resource is first offered, the RPM Auction Credit Requirement shall be reduced in direct proportion to the megawatts of firm transmission service secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

c. For Planned Generation Capacity Resources located in the PJM Region, the RPM Auction Credit Requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals.

Milestones	**Increment of reduction from initial RPM Auction Credit Requirement**
Effective Date of Interconnection Service Agreement	50%
Financial Close	15%
Full Notice to Proceed and Commencement of Construction (e.g., footers poured)	5%
Main Power Generating Equipment Delivered	5%
Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit Requirement, except for the Interconnection Service Agreement and Commencement of Interconnection Service milestones, the Capacity Market Seller must submit a sworn, notarized certification of a duly authorized independent engineer in a form acceptable to PJM, certifying that the engineer has personal knowledge, or has engaged in a diligent inquiry to determine, that the milestone has been achieved and that, based on its review of the relevant project information, the independent engineer is not aware of any information that could reasonably cause it to believe that the Capacity Resource will not be in-service by the beginning of the applicable Delivery Year. The Capacity Market Seller shall, if requested by PJM, supply to PJM on a confidential basis all records and documents relating to the independent engineer's certification.

d. For Planned External Generation Capacity Resources, the RPM Auction Credit Requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals; provided, however, that the total percentage reduction in the RPM Auction Credit Requirement shall be no greater than the quotient of (a) the MWs of firm transmission service that the Capacity Market Seller has secured for the complete transmission path divided by (b) the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Credit Reduction Milestones for Planned External Generation Capacity Resources	
Milestones	**Increment of reduction from initial RPM Auction Credit Requirement**

Effective Date of the equivalent of an Interconnection Service Agreement	50%
Financial Close	15%
Full Notice to Proceed and Commencement of Construction (e.g., footers poured)	5%
Main Power Generating Equipment Delivered	5%
Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit Requirement, the Capacity Market Seller must demonstrate satisfaction of the applicable milestone in the same manner as set forth for Planned Generation Capacity Resources in subsection (c) above.

e. For Planned Financed Generation Capacity Resources located in the PJM Region, the RPM Auction Credit Requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals.

Credit Reduction Milestones for Planned Financed Generation Capacity Resources	
Milestones	**Increment of reduction from initial RPM Auction Credit Requirement**
Full Notice to Proceed	50%
Commencement of Construction (e.g., footers poured)	15%
Main Power Generating Equipment Delivered	10%
Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit Requirement, the Capacity Market Seller must demonstrate satisfaction of the applicable milestone in the same manner as set forth for Planned Generation Capacity Resources in subsection (c) above.

f. For Planned External Financed Generation Capacity Resources, the RPM Credit Auction Requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals; provided, however, that the total percentage reduction in the RPM Auction Credit Requirement, including the initial 50% reduction for being a Planned External Financed Generation Capacity Resources, shall be no greater than the quotient of (a) the MWs of firm transmission service that the Capacity Market Seller has secured for the complete transmission path divided by (b) the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Credit Reduction Milestones for Planned External Financed Generation Capacity	
Milestones	**Increment of reduction from initial RPM Auction Credit Requirement**
Full Notice to Proceed	50%

Commencement of Construction (e.g., footers poured)	15%
Main Power Generating Equipment Delivered	10%
Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit Requirement, the Capacity Market Seller must demonstrate satisfaction of the applicable milestone in the same manner as set forth for Planned Generation Capacity Resources in subsection (c) above.

g. For Qualifying Transmission Upgrades, the RPM Auction Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B beginning as of the effective date of the latest associated Interconnection Service Agreement (or, when a project will have no such agreement, an Upgrade Construction Service Agreement), and shall be reduced to zero on the date the Qualifying Transmission Upgrade is placed in service. In addition, a Qualifying Transmission Upgrade will be allowed a reduction in its RPM Auction Credit Requirement equal to the amount of collateral currently posted with PJM for the facility construction when the Qualifying Transmission Upgrade meets the following requirements: the Upgrade Construction Service Agreement has been fully executed, the full estimated cost to complete as most recently determined or updated by PJM has been fully paid or collateralized, and all regulatory and other required approvals (except those that must await construction completion) have been obtained. Such reduction in RPM Auction Credit Requirement may not be transferred across different projects.

D. RPM Auction Credit Rate

As set forth in the PJM Manuals, a separate Auction Credit Rate shall be calculated for each Delivery Year prior to each Reliability Pricing Model Auction for such Delivery Year, as follows:

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the greater of ((A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year.

b. Subsequent to the posting of the results from a Base Residual Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).

c. For any resource not previously committed for a Delivery Year that seeks to participate in an Incremental Auction, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located or (C) $20 per MW-day) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the (greater of (A) 0.5 times Net Cost of New Entry for the PJM Region for such Delivery year or for the Relevant LDA or (B) $20/MW-day) times the number of days in such Delivery Year.

d. Subsequent to the posting of the results of an Incremental Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For Base Capacity Resources: (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year, but no greater than the Auction Credit Rate previously established for such resource's participation in such Incremental Auction pursuant to subsection (c) above) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).

e. For the purposes of this section IV.D, “Relevant LDA” means the Locational Deliverability Area in which the Capacity Performance Resource is located if a separate Variable Resource Requirement Curve has been established for that Locational Deliverability Area for the Base Residual Auction for such Delivery Year.

E. Price Responsive Demand Credit Rate

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (ii) $20 per MW-day) times the number of days in such Delivery Year;

b. Subsequent to the posting of the results from a Base Residual Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for Price Responsive Demand registered prior to such auction shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the PRD load is located) times the number of days in such Delivery Year times a final price uncertainty factor of 1.05;

c. For any additional Price Responsive Demand that seeks to commit in a Third Incremental Auction in response to a qualifying change in the final LDA load forecast, the Price Responsive Demand Credit Rate shall be the same as the rate for Price Responsive Demand that had cleared in the Base Residual Auction;

d. Subsequent to the posting of the results of the Third Incremental Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for all Price Responsive Demand, shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Final Zonal Capacity Price for the Locational Deliverability Area within which the Price Responsive Demand is located) times the number of days in such Delivery Year, but no greater than the Price Responsive Demand Credit Rate previously established under subsections (a), (b), or (c) of this section for such Delivery Year.

F. RPM Seller Credit - Additional Form of Unsecured Credit for RPM

In addition to the forms of credit specified elsewhere in this Attachment Q, RPM Seller Credit shall be available to Market Sellers, but solely for purposes of satisfying RPM Auction Credit Requirements. If a supplier has a history of being a net seller into PJM markets, on average, over the past 12 months, then PJMSettlement will count as available Unsecured Credit twice the average of that participant’s total net monthly PJMSettlement bills over the past 12 months. This RPM Seller Credit shall be subject to the cap on available Unsecured Credit as established in Section II.F.

G. Credit Responsibility for Traded Planned RPM Capacity Resources

PJMSettlement may require that credit and financial responsibility for planned RPM Capacity Resources that are traded remain with the original party (which for these purposes, means the party bearing credit responsibility for the planned RPM Capacity Resource immediately prior to trade) unless the receiving party independently establishes consistent with the PJM credit policy, that it has sufficient credit with PJMSettlement and agrees by providing written notice to PJMSettlement that it will fully assume the credit responsibility associated with the traded planned RPM Capacity Resource.

V. FINANCIAL TRANSMISSION RIGHT AUCTIONS

A. FTR Credit Limit.

PJMSettlement will establish an FTR Credit Limit for each Participant. Participants must maintain their FTR Credit Limit at a level equal to or greater than their FTR Credit Requirement. FTR Credit Limits will be established only by a Participant providing Financial Security.

B. FTR Credit Requirement.

For each Participant with FTR activity, PJMSettlement shall calculate an FTR Credit Requirement based on FTR cost less a discounted historical value. FTR Credit Requirements shall be further adjusted by ARR credits available and by an amount based on portfolio diversification, if applicable. The requirement will be based on individual monthly exposures which are then used to derive a total requirement.

The FTR Credit Requirement shall be calculated by first adding for each month the FTR Monthly Credit Requirement Contribution for each submitted, accepted, and cleared FTR and then subtracting the prorated value of any ARRs held by the Participant for that month. The resulting twelve monthly subtotals represent the expected value of net payments between PJMSettlement and the Participant for FTR activity each month during the Planning Period. Subject to later adjustment by an amount based on portfolio diversification, if applicable, the FTR Credit Requirement shall be the sum of the individual positive monthly subtotals, representing months in which net payments to PJMSettlement are expected.

C. Rejection of FTR Bids.

Bids submitted into an auction will be rejected if the Participant's FTR Credit Requirement including such submitted bids would exceed the Participant's FTR Credit Limit, or if the Participant fails to establish additional credit as required pursuant to provisions related to portfolio diversification.

D. FTR Credit Collateral Returns.

A Market Participant may request from PJMSettlement the return of any collateral no longer required for the FTR auctions. PJMSettlement is permitted to limit the frequency of such requested collateral returns, provided that collateral returns shall be made by PJMSettlement at least once per calendar quarter, if requested by a Market Participant.

E. Credit Responsibility for Traded FTRs.

PJMSettlement may require that credit responsibility associated with an FTR traded within PJM's eFTR system remain with the original party (which for these purposes, means the party bearing credit responsibility for the FTR immediately prior to trade) unless and until the receiving party independently establishes, consistent with the PJM credit policy, sufficient credit with PJMSettlement and agrees through confirmation of the FTR trade within the eFTR system that it will meet in full the credit requirements associated with the traded FTR.

F. Portfolio Diversification.

Subsequent to calculating a tentative cleared solution for an FTR auction (or auction round), PJM shall both:

1. Determine the FTR Portfolio Auction Value, including the tentative cleared solution. Any Participants with such FTR Portfolio Auction Values that are negative shall be deemed FTR Flow Undiversified.

2. Measure the geographic concentration of the FTR Flow Undiversified portfolios by testing such portfolios using a simulation model including, one at a time, each planned transmission outage or other network change which would substantially affect the network for the specific auction period. A list of such planned outages or changes anticipated to be modeled shall be posted prior to commencement of the auction (or auction round). Any FTR Flow Undiversified portfolio that experiences a net reduction in calculated congestion credits as a result of any one or more of such modeled outages or changes shall be deemed FTR Geographically Undiversified.

For portfolios that are FTR Flow Undiversified but not FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to twice the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For Participants with portfolios that are both FTR Flow Undiversified and FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to three times the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For portfolios that are FTR Flow Undiversified in months subsequent to the current planning year, these incremental amounts, calculated on a monthly basis, shall be reduced (but not below zero) by an amount up to 25% of the monthly value of ARR credits that are held by a Participant. Subsequent to the ARR allocation process preceding an annual FTR auction, such ARRs credits shall be reduced to zero for months associated with that ARR allocation process. PJMSettlement may recalculate such ARR credits at any time, but at a minimum shall do so subsequent to each annual FTR auction. If a reduction in such ARR credits at any time increases the amount of credit required for the Participant beyond its credit available for FTR activity, the Participant must increase its credit to eliminate the shortfall.

If the FTR Credit Requirement for any Participant exceeds its credit available for FTRs as a result of these diversification requirements for the tentatively cleared portfolio of FTRs, PJMSettlement shall immediately issue a demand for additional credit, and such demand must be fulfilled before 4:00 p.m. on the business day following the demand. If any Participant does not timely satisfy such demand, PJMSettlement, in coordination with PJM, shall cause the removal that Participant's entire set of bids for that FTR auction (or auction round) and a new cleared solution shall be calculated for the entire auction (or auction round).

If necessary, PJM shall repeat the auction clearing calculation. PJM shall repeat these portfolio diversification calculations subsequent to any such secondary clearing calculation, and PJMSettlement shall require affected Participants to establish additional credit.

G. FTR Administrative Charge Credit Requirement

In addition to any other credit requirements, PJMSettlement may apply a credit requirement to cover the maximum administrative fees that may be charged to a Participant for its bids and offers.

H. Long-Term FTR Credit Recalculation

Long-term FTR Credit Requirement calculations shall be updated annually for known history, consistent with updating of historical values used for FTR Credit Requirement calculations in the annual auctions.

VI. EXPORT TRANSACTION SCREENING

Export Transactions in the Real-time Energy Market shall be subject to Export Transaction Screening. Export Transaction Screening may be performed either for the duration of the entire Export Transaction, or separately for each time interval comprising an Export Transaction. PJM will deny or curtail all or a portion (based on the relevant time interval) of an Export Transaction if that Export Transaction, or portion thereof, would otherwise cause the Market Participant's Export Credit Exposure to exceed its Credit Available for Export Transactions. Export Transaction Screening shall be applied separately for each Operating Day and shall also be applied to each Export Transaction one or more times prior to the market clearing process for each relevant time interval. Export Transaction Screening shall not apply to transactions established directly by and between PJM and a neighboring Balancing Authority for the purpose of maintaining reliability.

A Market Participant’s credit exposure for an individual Export Transaction shall be the MWh volume of the Export Transaction for each relevant time interval multiplied by each relevant Export Transaction Price Factor and summed over all relevant time intervals of the Export Transaction.

VII. FORMS OF FINANCIAL SECURITY

Participants that provide Financial Security must provide the security in a PJMSettlement approved form and amount according to the guidelines below.

Financial Security which is no longer required to be maintained under provisions of the Agreements shall be returned at the request of a participant no later than two Business Days following determination by PJMSettlement within a commercially reasonable period of time that such collateral is not required.

Except when an event of default has occurred, a Participant may substitute an approved PJMSettlement form of Financial Security for another PJMSettlement approved form of Financial Security of equal value. The Participant must provide three (3) Business Days notice to PJMSettlement of its intent to substitute the Financial Security. PJMSettlement will release the replaced Financial Security with interest, if applicable, within (3) Business Days of receiving an approved form of substitute Financial Security.

A. Cash Deposit

Cash provided by a Participant as Financial Security will be held in a depository account by PJMSettlement with interest earned at PJMSettlement's overnight bank rate, and accrued to the Participant. PJMSettlement also may establish an array of investment options among which a Participant may choose to invest its cash deposited as Financial Security. Such investment options shall be comprised of high quality debt instruments, as determined by PJMSettlement, and may include obligations issued by the federal government and/or federal government sponsored enterprises. These investment options will reside in accounts held in PJMSettlement's name in a banking or financial institution acceptable to PJMSettlement. Where practicable, PJMSettlement may establish a means for the Participant to communicate directly with the bank or financial institution to permit the Participant to direct certain activity in the PJMSettlement account in which its Financial Security is held. PJMSettlement will establish and publish procedural rules, identifying the investment options and respective discounts in collateral value that will be taken to reflect any liquidation, market and/or credit risk presented by such investments. PJMSettlement has the right to liquidate all or a portion of the account balances at its discretion to satisfy a Participant's Total Net Obligation to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

B. Letter Of Credit

An unconditional, irrevocable standby letter of credit can be utilized to meet the Financial Security requirement. As stated below, the form, substance, and provider of the letter of credit must all be acceptable to PJMSettlement.

- The letter of credit will only be accepted from U.S.-based financial institutions or U.S. branches of foreign financial institutions ("financial institutions") that have a minimum corporate debt rating of "A" by Standard & Poor's or Fitch Ratings, or "A2" from Moody's Investors Service, or an equivalent short term rating from one of these agencies. PJMSettlement will consider the lowest applicable rating to be the rating of the financial institution. If the rating of a financial institution providing a letter of credit is lowered below A/A2 by any rating agency, then PJMSettlement may require the Participant to provide a letter of credit from another financial institution that is rated A/A2 or better, or to provide a cash deposit. If a letter of credit is provided from a U.S. branch of a foreign institution, the U.S. branch must itself comply with the terms of this credit policy, including having its own acceptable credit rating.

- The letter of credit shall state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety (90) days prior written notice from the issuing financial institution. If PJM or PJMSettlement receives notice from the issuing financial institution that the current letter of credit is being cancelled, the Participant will be required to provide evidence, acceptable to PJMSettlement, that such letter of credit will be replaced with appropriate Financial Security, effective as of the cancellation date of the letter of credit, no later than thirty (30) days before the cancellation date of the letter of credit, and no later than ninety (90) days after the notice of cancellation. Failure to do so will constitute a default under this credit policy and one of more of the Agreements.

- The letter of credit must clearly state the full names of the "Issuer", "Account Party" and "Beneficiary" (PJMSettlement), the dollar amount available for drawings, and shall specify that funds will be disbursed upon presentation of the drawing certificate in accordance with the instructions stated in the letter of credit. The letter of credit should specify any statement that is required to be on the drawing certificate, and any other terms and conditions that apply to such drawings.

- The PJMSettlement Credit Application contains an acceptable form of a letter of credit that should be utilized by a Participant choosing to meet its Financial Security requirement with a letter of credit. If the letter of credit varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a letter of credit and meeting the policy provisions are the responsibility of the Participant

- PJMSettlement may accept a letter of credit from a Financial Institution that does not meet the credit standards of this policy provided that the letter of credit has third-party support, in a form acceptable to PJMSettlement, from a financial institution that does meet the credit standards of this policy.

VIII. POLICY BREACH AND EVENTS OF DEFAULT

A Participant will have two Business Days from notification of Breach (including late payment notice) or notification of a Collateral Call to remedy the Breach or satisfy the Collateral Call in a manner deemed acceptable by PJMSettlement. Failure to remedy the Breach or satisfy such Collateral Call within such two Business Days will be considered an event of default. If a Participant fails to meet the requirements of this policy but then remedies the Breach or satisfies a Collateral Call within the two Business Day cure period, then the Participant shall be deemed to have complied with the policy. Any such two Business Day cure period will expire at 4:00 p.m. eastern prevailing time on the final day.

Only one cure period shall apply to a single event giving rise to a breach or default. Application of Financial Security towards a non-payment Breach shall not be considered a satisfactory cure of the Breach if the Participant fails to meet all requirements of this policy after such application.

Failure to comply with this policy (except for the responsibility of a Participant to notify PJMSettlement of a Material change) shall be considered an event of default. Pursuant to § 15.1.3(a) of the Operating Agreement of PJM Interconnection, L.L.C. and § I.7.3 of the PJM Open Access Transmission Tariff, non-compliance with the PJMSettlement credit policy is an event of default under those respective Agreements. In event of default under this credit policy or one or more of the Agreements, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant’s ongoing Transmission Service and participation in PJM Markets. PJMSettlement has the right to liquidate all or a portion of a Participant’s Financial Security at its discretion to satisfy Total Net Obligations to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

PJMSettlement may hold a defaulting Participant’s Financial Security for as long as such party’s positions exist and consistent with the PJM credit policy in this Attachment Q, in order to protect PJM’s membership from default.

No payments shall be due to a Participant, nor shall any payments be made to a Participant, while the Participant is in default or has been declared in Breach of this policy or the Agreements, or while a Collateral Call is outstanding. PJMSettlement may apply towards an ongoing default any amounts that are held or later become available or due to the defaulting Participant through PJM's markets and systems.

In order to cover Obligations, PJMSettlement may hold a Participant's Financial Security through the end of the billing period which includes the 90th day following the last day a Participant had activity, open positions, or accruing obligations (other than reconciliations and true-ups), and until such Participant has satisfactorily paid any obligations invoiced through such period. Obligations incurred or accrued through such period shall survive any withdrawal from PJM. In event of non-payment, PJMSettlement may apply such Financial Security to such Participant's Obligations, even if Participant had previously announced and effected its withdrawal from PJM.

IX. DEFINITIONS:

All capitalized terms in this Attachment Q that are not otherwise defined herein shall have the same meaning as they are defined in the Agreements.

Affiliate
Affiliate is defined in the PJM Operating Agreement, §1.2.

Agreements
Agreements are the Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, the Reliability Assurance Agreement – West, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Applicant
Applicant is an entity desiring to become a PJM Member, or to take Transmission Service that has submitted the PJMSettlement Credit Application, PJMSettlement Credit Agreement and other required submittals as set forth in this policy.

Breach
Breach is the status of a Participant that does not currently meet the requirements of this policy or other provisions of the Agreements.

Business Day
A Business Day is a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Canadian Guaranty
Canadian Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of this credit policy.

Capacity
Capacity is the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Collateral Call
Collateral Call is a notice to a Participant that additional Financial Security, or possibly early payment, is required in order to remain in, or to regain, compliance with this policy.

Corporate Guaranty
Corporate Guaranty is a legal document used by one entity to guaranty the obligations of another entity.

Credit Available for Export Transactions
Credit Available for Export Transactions is a set-aside of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions
A Market Participant’s Credit Available for Virtual Transactions is the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy.

Credit-Limited Offer

Credit-Limited Offer shall mean a Sell Offer that is submitted by a Market Seller in an RPM Auction subject to a maximum credit requirement specified by such Market Seller.

Credit Score
Credit Score is a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

Export Credit Exposure
Export Credit Exposure is determined for each Market Participant for a given Operating Day, and is the sum of credit exposures for the Market Participant's Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price
The Export Nodal Reference Price at each location is the 97th percentile real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction
An Export Transaction is a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transactions Net Activity
Export Transactions Net Activity shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Export Transaction Price Factor
The Export Transaction Price Factor for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening
Export Transaction Screening is the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Financial Close
Financial Close shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Security
Financial Security is a cash deposit or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Foreign Guaranty
Foreign Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of this credit policy.

FTR Credit Limit
FTR Credit Limit will be equal to the amount of credit established with PJMSettlement that a Participant has specifically designated to PJMSettlement to be set aside and used for FTR activity. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the Participant may have with PJMSettlement.

FTR Credit Requirement
FTR Credit Requirement is the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or is bidding for. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems.

FTR Flow Undiversified
FTR Flow Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Geographically Undiversified
FTR Geographically Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Historical Value

FTR Historical Value – For each FTR for each month, this is the historical weighted average value over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year. FTR Historical Values shall be calculated separately for on-peak, off-peak, and 24-hour FTRs for each month of the year. FTR Historical Values shall be adjusted by plus or minus ten percent (10%) for cleared counterflow or normal flow FTRs, respectively, in order to mitigate exposure due to uncertainty and fluctuations in actual FTR value.

FTR Monthly Credit Requirement Contribution
FTR Monthly Credit Requirement Contribution - For each FTR for each month, this is the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity
FTR Net Activity shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant
FTR Participant shall mean any Market Participant that is required to provide Financial Security in order to participate in PJM's FTR auctions.

FTR Portfolio Auction Value
FTR Portfolio Auction Value shall mean for each Participant (or Participant account), the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Full Notice to Proceed
Full Notice to Proceed shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Market Participant
Market Participant shall have the meaning provided in the Operating Agreement.

Material
For these purposes, material is defined in §I.B.3, Material Changes. For the purposes herein, the use of the term "material" is not necessarily synonymous with use of the term by governmental agencies and regulatory bodies.

Member
Member shall have the meaning provided in the Operating Agreement.

Minimum Participation Requirements

A set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM markets, as set forth herein and in the Form of Annual Certification set forth as Appendix 1 to this Attachment Q. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Appendix 1 to this Attachment Q.

Net Obligation

Net Obligation is the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position

Net Sell Position is the amount of Net Obligation when Net Obligation is negative.

Nodal Reference Price

The Nodal Reference Price at each location is the 97th percentile price differential between hourly day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. In order to capture seasonality effects and maintain a two-month reference period, reference months will be grouped by two, starting with January (e.g., Jan-Feb, Mar-Apr, … , Jul-Aug, … Nov-Dec). For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

Obligation

Obligation is all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for Capacity purchases within the PJM Capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Operating Agreement of PJM Interconnection, L.L.C., (“Operating Agreement”)

The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of June 2, 1997, on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Participant

A Participant is a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer.

Peak Market Activity
Peak Market Activity is a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of section II.D of this Credit Policy.

Planned Financed Generation Capacity Resource
Planned Financed Generation Capacity Resource shall mean a Planned Generation Capacity Resource that, prior to August 7, 2015, has an effective Interconnection Service Agreement and has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close.

Planned External Financed Generation Capacity Resource
Planned External Financed Generation Capacity Resource shall mean a Planned External Generation Capacity Resource that, prior to August 7, 2015, has an effective agreement that is the equivalent of an Interconnection Service Agreement, has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close, and has secured at least 50 percent of the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

PJM Markets
The PJM Markets are the PJM Interchange Energy Market and the PJM Capacity markets as established by the Operating Agreement. Also any other markets that exist or may be established in the future wherein Participants may incur Obligations to PJMSettlement.

PJM Open Access Transmission Tariff (“O.A.T.T.”)
The Open Access Transmission Tariff of PJM Interconnection, L.L.C., on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Reliability Assurance Agreement (“R.A.A.”)
See the definition of the Reliability Assurance Agreement (“R.A.A.”) in the Operating Agreement.

RPM Seller Credit
RPM Seller Credit is an additional form of Unsecured Credit defined in section IV of this document.

Tangible Net Worth
Tangible Net Worth is all assets (not including any intangible assets such as goodwill) less all liabilities. Any such calculation may be reduced by PJMSettlement upon review of the available financial information.

Total Net Obligation
Total Net Obligation is all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position
Total Net Sell Position is all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Transmission Customer
Transmission Customer is a Transmission Customer is an entity taking service under Part II or Part III of the O.A.T.T.

Transmission Service
Transmission Service is any or all of the transmission services provided by PJM pursuant to Part II or Part III of the O.A.T.T.

Uncleared Bid Exposure
Uncleared Bid Exposure is a measure of exposure from Increment Offers and Decrement Bids activity relative to a Participant's established credit as defined in this policy. It is used only as a pre-screen to determine whether a Participant's Increment Offers and Decrement Bids should be subject to Increment Offer and Decrement Bid Screening.

Unsecured Credit
Unsecured Credit is any credit granted by PJMSettlement to a Participant that is not secured by a form of Financial Security.

Unsecured Credit Allowance
Unsecured Credit Allowance is Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Financial Security. See also: "Working Credit Limit."

Up-to Congestion Counterflow Transaction
An Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month
An Up-to Congestion Historical Month is a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction
An Up-to Congestion Transaction will be deemed an Up-to Congestion Prevailing Flow Transaction if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price
The Up-to Congestion Reference Price for an Up-to Congestion Transaction is the specified percentile price differential between source and sink (defined as sink price minus source price)

for hourly real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30^{th} percentile
For Up-to Congestion Counterflow Transactions when bid: 20^{th} percentile
For Up-to Congestion Counterflow Transactions when cleared: 5^{th} percentile

Virtual Credit Exposure
Virtual Credit Exposure is the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in this policy.

Virtual Transaction Screening
Virtual Transaction Screening is the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity
Virtual Transactions Net Activity shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Virtual Transactions Net Activity may be positive or negative.

Working Credit Limit
Working Credit Limit amount is 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement. The Working Credit Limit establishes the maximum amount of Total Net Obligation that a Market Participant may have outstanding at any time. The calculation of Working Credit Limit shall take into account applicable reductions for Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Working Credit Limit for Virtual Transactions
The Working Credit Limit for Virtual Transactions shall be calculated as 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement when the Market Participant is at or below its Peak Market Activity credit requirements as specified in section II.D of this Credit Policy. When the Market Participant provides additional Unsecured Credit Allowance and/or Financial Security in excess of its Peak Market Activity credit requirements, such additional Unsecured Credit Allowance and/or Financial Security shall not be discounted by 25% when calculating the Working Credit Limit for Virtual Transactions. The Working Credit Limit for Virtual Transactions is a component in the calculation of Credit Available for Virtual Transactions. The calculation of Working Credit Limit for Virtual Transactions shall take into account applicable reductions for Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Appendix 1 to Attachment Q

PJM MINIMUM PARTICIPATION CRITERIA
OFFICER CERTIFICATION FORM

Participant Name: ______________________________________ ("Participant")

I, ____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. and PJM Settlement, Inc. (”PJMSettlement”) are relying on this certification as evidence that Participant meets the minimum requirements set forth in Attachment Q to the PJM Open Access Transmission Tariff ("PJM Tariff"), hereby certify that I have full authority to represent on behalf of Participant and further represent as follows, as evidenced by my initialing each representation in the space provided below:

1. All employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Amended and Restated Operating Agreement (“PJM Operating Agreement”) on behalf of the Participant have received appropriate[1] training and are authorized to transact on behalf of Participant.__________

2. Participant has written risk management policies, procedures, and controls, approved by Participant’s independent risk management function[2] and applicable to transactions in the PJM markets in which it participates and for which employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Operating Agreement have been trained, that provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Participant is exposed, including, but not limited to credit risks, liquidity risks and market risks.___________

3. An FTR Participant (as defined in Attachment Q to the PJM Tariff) must make either the following 3.a. or 3.b. additional representations, evidenced by the undersigned officer initialing either the one 3.a. representation or the six 3.b. representations in the spaces provided below:

   3.a. Participant transacts in PJM’s FTR markets with the sole intent to hedge congestion risk in connection with either obligations Participant has to serve load or rights Participant has to generate electricity in the PJM Region (“physical

[1] As used in this representation, the term “appropriate” as used with respect to training means training that is (i) comparable to generally accepted practices in the energy trading industry, and (ii) commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the participant.

[2] As used in this representation, a Participant’s “independent risk management function” can include appropriate corporate persons or bodies that are independent of the Participant’s trading functions, such as a risk management committee, a risk officer, a Participant’s board or board committee, or a board or committee of the Participant’s parent company.

transactions") and monitors all of the Participant's FTR market activity to endeavor to ensure that its FTR positions, considering both the size and pathways of the positions, are either generally proportionate to or generally do not exceed the Participant's physical transactions, and remain generally consistent with the Participant's intention to hedge its physical transactions.__________

3.b. On no less than a weekly basis, Participant values its FTR positions and engages in a probabilistic assessment of the hypothetical risk of such positions using analytically based methodologies, predicated on the use of industry accepted valuation methodologies.__________

Such valuation and risk assessment functions are performed either by persons within Participant's organization independent from those trading in PJM's FTR markets or by an outside firm qualified and with expertise in this area of risk management.__________

Having valued its FTR positions and quantified their hypothetical risks, Participant applies its written policies, procedures and controls to limit its risks using industry recognized practices, such as value-at-risk limitations, concentration limits, or other controls designed to prevent Participant from purposefully or unintentionally taking on risk that is not commensurate or proportional to Participant's financial capability to manage such risk.__________

Exceptions to Participant's written risk policies, procedures and controls applicable to Participant's FTR positions are documented and explain a reasoned basis for the granting of any exception.__________

Participant has provided to PJMSettlement, in accordance with Section I A. of Attachment Q to the PJM Tariff, a copy of its current governing risk management policies, procedures and controls applicable to its FTR trading activities.__________

If the risk management policies, procedures and controls applicable to Participant's FTR trading activities submitted to PJMSettlement were submitted prior to the current certification, Particpant certifies that no substantive changes have been made to such policies, procedures and controls applicable to its FTR trading activities since such submission.__________

4. Participant has appropriate personnel resources, operating procedures and technical abilities to promptly and effectively respond to all PJM communications and directions.__________

5. Participant has demonstrated compliance with the Minimum Capitalization criteria set forth in Attachment Q of the PJM Open Access Transmission Tariff that are applicable to the PJM market(s) in which Participant transacts, and is not aware of any change having occurred or being imminent that would invalidate such compliance.__________

6. All Participants must certify and initial in at least one of the four sections below:

   a. I certify that Participant qualifies as an “appropriate person” as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act or an “eligible contract participant” as that term is defined under Section 1a(18), or successor provision, of the Commodity Exchange Act. I certify that Participant will cease transacting in PJM’s Markets and notify PJMSettlement immediately if Participant no longer qualifies as an “appropriate person” or “eligible contract participant.”__________

      If providing financial statements to support Participant’s certification of qualification as an “appropriate person:”

      I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $5 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

      If providing financial statements to support Participant’s certification of qualification as an “eligible contract participant:”

      I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $10 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

   b. I certify that Participant has provided an unlimited Corporate Guaranty in a form acceptable to PJM as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant per Participant for which the issuer has issued an unlimited Corporate Guaranty. I certify that Participant will cease transacting PJM’s Markets and notify PJMSettlement immediately if issuer of the unlimited Corporate Guaranty for Participant no longer has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty.__________

I certify that the issuer of the unlimited Corporate Guaranty to Participant continues to have at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty. I acknowledge that PJM and PJMSettlement are relying upon my certifications to maintain compliance with federal regulatory requirements.__________

c. I certify that Participant fulfills the eligibility requirements of the Commodity Futures Trading Commission exemption order (78 F.R. 19880 – April 2, 2013) by being in the business of at least one of the following in the PJM Region as indicated below (initial those applicable):

1. Generating electric energy, including Participants that resell physical energy acquired from an entity generating electric energy:__________

2. Transmitting electric energy:__________

3. Distributing electric energy delivered under Point-to-Point or Network Integration Transmission Service, including scheduled import, export and wheel through transactions:__________

4. Other electric energy services that are necessary to support the reliable operation of the transmission system:__________

Description only if c(4) is initialed:

____

Further, I certify that Participant will cease transacting in PJM's Markets and notify PJMSettlement immediately if Participant no longer performs at least one of the functions noted above in the PJM Region. I acknowledge that PJM and PJMSettlement are relying on my certification to maintain compliance with federal energy regulatory requirements.__________

d. I certify that Participant has provided a letter of credit of $5 million or more to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Participant acknowledges cannot be utilized to meet its credit requirements to PJMSettlement. I acknowledge that PJM and PJMSettlement are relying on the provision of this letter of credit and my certification to maintain compliance with federal regulatory requirements.__________

7. I acknowledge that I have read and understood the provisions of Attachment Q of the PJM Tariff applicable to Participant's business in the PJM markets, including those provisions describing PJM's minimum participation requirements and the enforcement actions available to PJMSettlement of a Participant not satisfying those requirements. I acknowledge that the information provided herein is true and accurate to the best of my belief and knowledge after due investigation. In addition, by signing this Certification, I

acknowledge the potential consequences of making incomplete or false statements in this Certification.___________

Date: ______________________________ ____________________________________

(Signature)

Print Name: ____________________________________

Title: ____________________________________

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the Operating Agreement or RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1 Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1A Annual Energy Efficiency Resource

"Annual Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.2.01 Balancing Ratio

"Balancing Ratio" shall have the meaning provided in section 10A.

2.2A Base Capacity Demand Resource

"Base Capacity Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.2B Base Capacity Demand Resource Constraint

"Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.2C Base Capacity Demand Resource Price Decrement

"Base Capacity Demand Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

2.2D Base Capacity Energy Efficiency Resource

"Base Capacity Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.2E Base Capacity Resource

"Base Capacity Resource" shall mean a Capacity Resource as described in section 5.5A(b).

2.2F Base Capacity Resource Constraint

"Base Capacity Resource Reliability Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA

and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].
“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.2G Base Capacity Resource Price Decrement

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.3 Base Load Generation Resource

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.6A Compliance Aggregation Area (CAA)

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in section 6.6(g).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.11A Capacity Performance Resource

"Capacity Performance Resource" shall mean a Capacity Resource as described in section 5.5A(a).

2.11B Capacity Performance Transition Incremental Auction

"Capacity Performance Transition Incremental Auction" shall have the meaning specified in section 5.14D.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.13A Capacity Storage Resource

"Capacity Storage Resource" shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8, or, as to an FRR entity, in Schedule 8.1 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5, or pursuant to an FRR Capacity Plan.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor or DR Factor

"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

2.22 [Reserved for Future Use]

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.23A Emergency Action

“Emergency Action” shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

2.24 Energy Efficiency Resource

“Energy Efficiency Resource” shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24.01 Environmentally-Limited Resource

“Environmentally-Limited Resource” shall mean a resource which 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 by a governmental authority to operating only during declared PJM capacity emergencies.

2.24A Extended Summer Demand Resource

“Extended Summer Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

“Extended Summer Resource Price Adder” shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Sub-Annual Resource Reliability Target

“Sub-Annual Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 Generator Forced Outage

"Generator Forced Outage" shall have the meaning specified in the Operating Agreement.

2.33 Generator Maintenance Outage

"Generator Maintenance Outage" shall have the meaning specified in the Operating Agreement.

2.33A Generator Planned Outage

"Generator Planned Outage" shall have the meaning specified in the Operating Agreement.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Intermittent Resource

"Intermittent Resource" shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year , a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.48A Performance Assessment Hour

"Performance Assessment Hour" shall mean each whole or partial clock-hour for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Hours for a Base Capacity Resource shall not include any hours outside the calendar months of June through September.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Operating Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

“Reference Resource” shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/MWh.

2.59 Reliability Assurance Agreement

“Reliability Assurance Agreement” shall mean that certain “Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region,” on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

“Reliability Pricing Model Auction” or “RPM Auction” shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

2.60A Repowered / Repowering

“Repowering” or “Repowered” shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

“Resource Substitution Charge” shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

“Scheduled Incremental Auctions” shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

“Second Incremental Auction” shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

“Sell Offer” shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65B.01 Small Commercial Customer

"Small Commercial Customer," as used in Schedule 6 of the RAA and Attachment DD-1 of the Tariff, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C and 5.14E of this Attachment DD.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C and 5.14E of this attachment DD.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;

- the Variable Resource Requirement Curves for the PJM Region and each LDA;

- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;

- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;

- For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of

Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the Delivery years through May 31, 2018, the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;

- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;

- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- For the Delivery Years through May 31, 2018, for each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement

- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and

- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(2) of this Attachment, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(1) of this Attachment, and the conditions stated in section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, 5.14C and 5.14E of this Attachment DD. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR

Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by section 5.4(c)(3)(i) of this Attachment, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by section 5.4(c)(3)(ii) of this Attachment, plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, 5.14C and 5.14E of this Attachment DD; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. For the Delivery Years through May 31, 2018, if more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

(A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the

Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-

block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) General Rule. Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, or a Unit-Specific Exception with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) Applicability. A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including Repowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle technology) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility (as defined in Part 292 of FERC's regulations), where the Capacity Market Seller is the owner of the Qualifying Facility or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) MOPR Floor Offer Price. The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), a combined cycle generator ("CC"), and an integrated gasification combined cycle generator ("IGCC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT $/MW-yr	132,200	130,300	128,900	130,300
CC $/MW-yr	185,700	176,000	172,600	179,400
IGCC $/MW-yr	582,042	558,486	547,240	537,306

i) Commencing with the Delivery Year that begins on June 1, 2019, the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above,

except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3,198 per MW-year.

(4) Duration. The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until (and including) the first Delivery Year for which a Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) Effect of Exemption or Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption or exception and cleared the RPM Auction for which it obtained such exemption or exception shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(10) hereof.

(6) Self-Supply Exemption**.** A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated Utility and the MOPR Screened Generation Resource is planned

consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE's Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW

Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE's future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long

positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

vi) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vii) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of

the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak. Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) <u>Competitive Entry Exemption</u>. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs of the MOPR Screened Generation Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be "Competitive and Non-Discriminatory" only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period

identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(9) Exemption/Exception Process.

i) The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.

ii) The Capacity Market Seller must submit its request for a Unit-Specific Exception, Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption or exception that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption or exception criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller

shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

iii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption or exception request. The Office of the Interconnection shall also review all exemption and exception requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption or exception request. The Office of the Interconnection shall reject a requested exemption or exception if the Capacity Market Seller's request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request. If the Office of the Interconnection does not provide its determination on an exemption or exception request by no later than sixty-five (65) days after receipt of the exemption or exception request, the request shall be deemed granted. Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (5) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(10) <u>Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.</u>

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared

in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(10) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference

specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This transition provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, “Transition Delivery Years” and each a “Transition Delivery Year”) by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a “Qualified DR Provider.”

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission’s order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the

identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this section 5.14A. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this section 5.14A to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

   DRTC = (IAP – BRP) * DRMW

   Where:

   DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

   IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

   BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

   DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this section 5.14A, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

   a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

   b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

   c. an aggregate amount that exceeds:

      (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

      (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

      (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this section 5.14A shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this section 5.14A, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and

received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORd value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORd value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test

procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell

megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity

Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the endues customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery

Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance

with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand

response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider’s maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider’s maximum for any single Delivery Year of [such provider’s cleared Demand Resource quantity] plus [such provider’s quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider’s rights

and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine

reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office

of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events for all Demand Resources not committed as a Capacity Performance Resource occurring through May 31, 2018, and for Load Management Events for Demand Resources committed as a Base Capacity Resource or a Capacity Performance Resource occurring during the months of June through September:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events for Demand Resources committed as a Base Capacity Resource or as a Capacity Performance Resource occurring during the months of October through May:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of Schedule 1 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer

the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020

Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

Section(s) of the
PJM Operating Agreement

(Clean Format)

Definitions C - D

1.6 Capacity Resource.

"Capacity Resource" have the meaning provided in the Reliability Assurance Agreement.

1.6.01 Catastrophic Force Majeure.

"Catastrophic Force Majeure" shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection's determination is subject to review by the Commission.

1.6A Consolidated Transmission Owners Agreement.

"Consolidated Transmission Owners Agreement" dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

1.7 Control Area.

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7.01 Control Zone.

"Control Zone" shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

1.7.01a Counterparty.

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with Market Participants or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7.02 Default Allocation Assessment.

"Default Allocation Assessment" shall mean the assessment determined pursuant to section 15.2.2 of this Agreement.

1.7.03 Demand Resource.

"Demand Resource" shall have the meaning provided in the Reliability Assurance Agreement.

1.7A Designated Entity.

An entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Section 1.5.8 of Schedule 6 of this Agreement.

1.7A.01 Direct Load Control:

Load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

1.7B [Reserved].

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1.01 Additional Day-ahead Scheduling Reserves Requirement

"Additional Day-ahead Scheduling Reserves Requirement" shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.001 Base Day-ahead Scheduling Reserves Requirement

"Base Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.01A Cold Weather Alert.

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.02A Coordinated External Transaction.

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.02B Coordinated Transaction Scheduling.

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Section 1.13 of Schedule 1 of this Agreement.

1.3.1B.02C CTS Enabled Interface.

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"), designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45).

1.3.1B.02D CTS Interface Bid

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

“Day-ahead Energy Market” shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

“Day-ahead Loss Price” shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

“Day-ahead Prices” shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

“Day-ahead Scheduling Reserves” shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

“Day-ahead Scheduling Reserves Requirement” shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

“Day-ahead Scheduling Reserves Resources” shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

“Day-ahead System Energy Price” shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"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.

1.3.1E.01 Demand Bid

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

1.3.1E.02 Demand Bid Limit

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.03 Demand Bid Screening

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.04 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1F.01 Emergency Load Response Program

The Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2A.02 Economic Maximum.

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.2B.01 Extended Primary Reserve Requirement

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.2B.02 Extended Synchronized Reserve Requirement

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9.01 Hot Weather Alert.

"Hot Weather Alert" shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

1.3.9A Increment Offer.

"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.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

1.3.11.02 Load Management Event

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11A.01 Location.

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.13A Maximum Generation Emergency Alert.

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.24A Pre-Emergency Load Response Program

The Pre-Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve.

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider.

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price.

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation.

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand.

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve.

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.29G Primary Reserve Requirement

"Primary Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2(h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.01A Residual Metered Load.

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.001 Sub-meter.

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.02A Synchronized Reserve Requirement

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38.01 Up-to Congestion Transaction.

"Up-to Congestion Transaction" shall have the meaning specified in Section 1.10.1A of this Schedule.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.38B Virtual Transaction.

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone, when non-extraordinary conditions exist for the applicable twelve month period, as determined by PJM. If the lowest daily zonal peak load from the applicable twelve month period is abnormally low due to extraordinary conditions, as determined by PJM, Zonal Base Load shall mean the next lowest daily zonal peak load that was not affected by extraordinary conditions during the applicable twelve month period, increased by the projected load growth rate for the relevant Zone. For the purposes of this definition, extraordinary conditions shall mean a significant event, or combination of events, that affect the operation of the bulk power system in an atypical manner and results in an abnormal reduction in the consumption of energy within a Zone.

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 dynamically scheduled 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. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited 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.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. 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), 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, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, 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 hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all Generation Capacity Resources; and

ix) Shall not exceed an energy offer price of $1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00, for all Economic Load Response Resources;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, $1,100/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt 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. 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 per MWh 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 and no-load fees, 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 offer by a Market Seller of a Generation Capacity Resource 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 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. 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. The offer must equal or exceed 0.1 megawatts, and the offer 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. 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).

(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 MW 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, no-load 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.

(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 and no-load fees, 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 and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

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 or no-load fees.

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 dispatch 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 dispatch 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 any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. 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 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) *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.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

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

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

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a

Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

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

performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point

the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

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

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

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

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

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

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

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

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

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

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

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the applicable offer for energy on which the generating unit was committed in the Real-time Energy Market, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

The deviation of the generating unit's output is equal to the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

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

(ii) for each hour a unit is scheduled to produce energy in the Day-ahead Energy Market, but the unit is not called on by the Office of the

Interconnection and does not operate in real time, then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the applicable offer for energy on which the generating unit was committed in the Day-ahead Energy Market, inclusive of no-load costs, plus (D) the start-up cost, divided by the hours committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market; or

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

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

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

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

The deviation of the generating unit's output is equal to the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.
For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

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

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

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

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

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

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

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

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

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

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

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

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

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

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

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

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

where:

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

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

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

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

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

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

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

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized

Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve

Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Synchronized Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

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

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

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

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

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

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load

Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Primary Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

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

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

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

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

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

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

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

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

3.2.3B Reactive Services.

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

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

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

The deviation of the generating unit's output is equal to the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

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

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

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

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

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

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

where UB - URTLMP shall not be negative.

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

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

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of

Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Offer and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right or had an Up-to Congestion Transaction that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for a path at or near the path of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Offer, Decrement Bid or Up-to Congestion Transaction is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an unanticipated event outside the control of PJM that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule

1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, “mitigation”) rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target

Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

Section(s) of the
PJM Reliability Assurance Agreement

(Clean Format)

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically

incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total

Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the

PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the

current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the

threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand

Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction

for LDLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- Supplemental status reports, detailing Demand Resources available, as requested by PJM;
- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load

reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are

responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events for all Demand Resources not committed as a Capacity Performance Resource occurring through May 31, 2018, and for Load Management Events for Demand Resources committed as a Base Capacity Resource or a Capacity Performance Resource occurring during the months of June through September:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load

Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events for Demand Resources committed as a Base Capacity Resource or as a Capacity Performance Resource occurring during the months of October through May:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of Schedule 1 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of

the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A

Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

Attachment B

Copies of Revisions to the
PJM Open Access Transmission Tariff
Previously Filed

OATT Definitions E-F

EL15-29-000: Version 4.0.0, Filed 12/12/2014, Effective 04/01/2015

ER15-806-000: Version 3.0.1, Filed 12/31/2014, Effective 03/02/2015

Definitions – E - F

1.10A Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall have the same meaning provided in the Operating Agreement.

1.10B Economic Minimum:

The lowest incremental MW output level a unit can achieve while following economic dispatch.

1.11 Eligible Customer:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

1.11.01 Emergency Condition:

A condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

1.11A Energy Resource:

A generating facility that is not a Capacity Resource.

1.11A.01 Energy Settlement Area:

The bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

1.11B Energy Transmission Injection Rights:

The rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

1.11C Environmental Laws:

Applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

1.12 Facilities Study:

An engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate an Interconnection Request or Upgrade Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Interconnection Facilities necessary to accommodate the New Service Customer's New Service Request in accordance with Section 207 of Part VI of the Tariff.

1.12A Federal Power Act:

The Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

1.12B FERC:

The Federal Energy Regulatory Commission or its successor.

1.13 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.13A Firm Transmission Withdrawal Rights:

The rights to schedule energy and capacity withdrawals from a Point of Interconnection (as defined in Section 1.33A) of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

~~**1.13A.01 Force Majeure:**~~

~~Any cause beyond the control of the affected Interconnection Party or Construction Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which, in any of the foregoing cases, by exercise of due diligence such party could not reasonably have been expected to avoid, and which, by the exercise of due diligence, it has been unable to overcome. Force Majeure does not include (i) a failure of performance that is due to an affected party's own negligence or intentional wrongdoing; (ii) any removable or remediable causes (other than settlement of a strike or labor dispute) which an affected party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected party.~~

Definitions – E - F

1.10A Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall have the same meaning provided in the Operating Agreement.

1.10B Economic Minimum:

The lowest incremental MW output level a unit can achieve while following economic dispatch.

1.11 Eligible Customer:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

1.11.01 Emergency Condition:

A condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

1.11A Energy Resource:

A generating facility that is not a Capacity Resource.

1.11A.01 Energy Settlement Area:

The bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

1.11B Energy Transmission Injection Rights:

The rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

1.11C Environmental Laws:

Applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

1.11D Existing Generation Capacity Resource:

Existing Generation Capacity Resource shall have the meaning specified in the Reliability Assurance Agreement.

1.12 Facilities Study:

An engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate an Interconnection Request or Upgrade Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Interconnection Facilities necessary to accommodate the New Service Customer's New Service Request in accordance with Section 207 of Part VI of the Tariff.

1.12A Federal Power Act:

The Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

1.12B FERC:

The Federal Energy Regulatory Commission or its successor.

1.13 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.13A Firm Transmission Withdrawal Rights:

The rights to schedule energy and capacity withdrawals from a Point of Interconnection (as defined in Section 1.33A) of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

1.13A.01 Force Majeure:

Any cause beyond the control of the affected Interconnection Party or Construction Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which, in any of the foregoing cases, by exercise of due diligence such party could not reasonably have been expected to avoid, and which, by the exercise of due diligence, it has been unable to overcome. Force Majeure does not include (i) a failure of performance that is due to an affected party's own negligence or intentional wrongdoing; (ii) any removable or remediable causes (other than settlement of a strike or labor dispute) which an affected party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected party.

OATT ATT K-Appendix Section 1.3

EL15-29-000: Version 21.0.0, Filed 12/12/2014, Effective 04/01/2015

ER15-643-000: Version 22.0.1, Filed 12/17/14, Effective 03/01/2015

ER15-643-001: Version 22.1.1, Filed 02/11/15, Effective 03/01/2015

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.01A Cold Weather Alert.

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.02A Coordinated External Transaction.

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.02B Coordinated Transaction Scheduling.

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Section 1.13 of ~~this~~ Schedule 1 of this Agreement.

1.3.1B.02C CTS Enabled Interface.

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"), designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45).

1.3.1B.02D CTS Interface Bid

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"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.

1.3.1E.01 Demand Bid

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

1.3.1E.02 Demand Bid Limit

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.03 Demand Bid Screening

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.04 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1F.01 Emergency Load Response Program

The Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

1.3.2A.01 Economic Minimum.

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2A.02 Economic Maximum.

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.3 External Market Buyer.

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9.01 Hot Weather Alert.

"Hot Weather Alert" shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

1.3.9A Increment Offer.

"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.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

1.3.11.02 Load Management Event

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11A.01 Location.

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.13A Maximum Generation Emergency Alert.

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic F~~f~~orce M~~m~~ajeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.24A Pre-Emergency Load Response Program

The Pre-Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve.

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider.

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price.

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation.

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand.

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve.

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2 (h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.01A Residual Metered Load.

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.001 Sub-meter.

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38.01 Up-to Congestion Transaction.

"Up-to Congestion Transaction" shall have the meaning specified in Section 1.10.1A of this Schedule.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.38B Virtual Transaction.

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone, when non-extraordinary conditions exist for the applicable twelve month period, as determined by PJM. If the lowest daily zonal peak load from the applicable twelve month period is abnormally low due to extraordinary conditions, as determined by PJM, Zonal Base Load shall mean the next lowest daily zonal peak load that was not affected by extraordinary conditions during the applicable twelve month period, increased by the projected load growth rate for the relevant Zone. For the purposes of this definition, extraordinary conditions shall mean a significant event, or combination of events, that affect the operation of the bulk power system in an atypical manner and results in an abnormal reduction in the consumption of energy within a Zone.

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1.01 Additional Day-ahead Scheduling Reserves Requirement

"Additional Day-ahead Scheduling Reserves Requirement" shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.001 Base Day-ahead Scheduling Reserves Requirement

"Base Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.01A Cold Weather Alert.

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.02A Coordinated External Transaction.

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.02B Coordinated Transaction Scheduling.

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Section 1.13 of Schedule 1 of this Agreement.

1.3.1B.02C CTS Enabled Interface.

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"), designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45).

1.3.1B.02D CTS Interface Bid

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement. ~~thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.~~

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"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.

1.3.1E.01 Demand Bid

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

1.3.1E.02 Demand Bid Limit

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.03 Demand Bid Screening

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.04 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1F.01 Emergency Load Response Program

The Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2A.02 Economic Maximum.

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.2B.01 Extended Primary Reserve Requirement

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.2B.02 Extended Synchronized Reserve Requiremen~~en~~t

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9.01 Hot Weather Alert.

"Hot Weather Alert" shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

1.3.9A Increment Offer.

"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.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

1.3.11.02 Load Management Event

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11A.01 Location.

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum

Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.13A Maximum Generation Emergency Alert.

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

“Network Service User” shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of *Catastrophic F*orce *M*ajeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

“Non-Variable Loads” shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

“Offer Data” shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

“Office of the Interconnection Control Center” shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

“On-Site Generators” shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

“Operating Day” shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

“Operating Margin” shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

“Operating Margin Customer” shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.24A Pre-Emergency Load Response Program

The Pre-Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29   Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve.

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider.

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price.

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation.

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand.

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve.

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.29G Primary Reserve Requirement

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.30 Ramping Capability.

“Ramping Capability” shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

“Real-time Congestion Price” shall mean the Congestion Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

“Real-time Loss Price” shall mean the Loss Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

“Real-time Prices” shall mean the Locational Marginal Prices resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

“Real-time Energy Market” shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

“Real-time System Energy Price” shall mean the System Energy Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

“Reserve Penalty Factor” shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

1.3.31.01 Residual Auction Revenue Rights.

“Residual Auction Revenue Rights” shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2 (h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.01A Residual Metered Load.

“Residual Metered Load” shall mean all load remaining in an electric distribution company’s fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

1.3.31.02 Special Member.

“Special Member” shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

1.3.32 Spot Market Backup.

“Spot Market Backup” shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

“State Estimator” shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.001 Sub-meter.

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.02A Synchronized Reserve Requirement

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38.01 Up-to Congestion Transaction.

"Up-to Congestion Transaction" shall have the meaning specified in Section 1.10.1A of this Schedule.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.38B Virtual Transaction.

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone, when non-extraordinary conditions exist for the applicable twelve month period, as determined by PJM. If the lowest daily zonal peak load from the applicable twelve month period is abnormally low due to extraordinary conditions, as determined by PJM, Zonal Base Load shall mean the next lowest daily zonal peak load that was not affected by extraordinary conditions during the applicable twelve month period, increased by the projected load growth rate for the relevant Zone. For the purposes of this definition, extraordinary conditions shall mean a significant event, or combination of events, that affect the operation of the bulk power system in an atypical manner and results in an abnormal reduction in the consumption of energy within a Zone.

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1.01 Additional Day-ahead Scheduling Reserves Requirement

"Additional Day-ahead Scheduling Reserves Requirement" shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.001 Base Day-ahead Scheduling Reserves Requirement

"Base Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.01A Cold Weather Alert.

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

1.3.1B.02 Congestion Price.

“Congestion Price” shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.02A Coordinated External Transaction.

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.02B Coordinated Transaction Scheduling.

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Section 1.13 of Schedule 1 of this Agreement.

1.3.1B.02C CTS Enabled Interface.

“CTS Enabled Interface” shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling (“CTS”), designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45).

1.3.1B.02D CTS Interface Bid

“CTS Interface Bid” shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

“Curtailment Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

“Day-ahead Congestion Price” shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement. ~~thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.~~

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"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.

1.3.1E.01 Demand Bid

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

1.3.1E.02 Demand Bid Limit

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.03 Demand Bid Screening

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.04 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1F.01 Emergency Load Response Program

The Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2A.02 Economic Maximum.

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.2B.01 Extended Primary Reserve Requirement

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.2B.02 Extended Synchronized Reserve Requiremen~~en~~t

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9.01 Hot Weather Alert.

"Hot Weather Alert" shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

1.3.9A Increment Offer.

"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.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

1.3.11.02 Load Management Event

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

1.3.11A Load Reduction Event.

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11A.01 Location.

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

1.3.11B Loss Price.

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum

Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.13A Maximum Generation Emergency Alert.

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

“Network Service User” shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of *Catastrophic F*orce *M*ajeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

“Non-Variable Loads” shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.24A Pre-Emergency Load Response Program

The Pre-Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29   Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve.

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider.

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price.

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation.

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand.

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve.

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.29G Primary Reserve Requirement

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.30 Ramping Capability.

“Ramping Capability” shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

“Real-time Congestion Price” shall mean the Congestion Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

“Real-time Loss Price” shall mean the Loss Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

“Real-time Prices” shall mean the Locational Marginal Prices resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

“Real-time Energy Market” shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

“Real-time System Energy Price” shall mean the System Energy Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2 (h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.01A Residual Metered Load.

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.001 Sub-meter.

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.02A Synchronized Reserve Requirement

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38.01 Up-to Congestion Transaction.

"Up-to Congestion Transaction" shall have the meaning specified in Section 1.10.1A of this Schedule.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.38B Virtual Transaction.

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone, when non-extraordinary conditions exist for the applicable twelve month period, as determined by PJM. If the lowest daily zonal peak load from the applicable twelve month period is abnormally low due to extraordinary conditions, as determined by PJM, Zonal Base Load shall mean the next lowest daily zonal peak load that was not affected by extraordinary conditions during the applicable twelve month period, increased by the projected load growth rate for the relevant Zone. For the purposes of this definition, extraordinary conditions shall mean a significant event, or combination of events, that affect the operation of the bulk power system in an atypical manner and results in an abnormal reduction in the consumption of energy within a Zone.

OATT ATT K-Appendix Section 1.10

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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 12:00 noon 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 dynamically scheduled 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. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited 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.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. 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), 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. Market Sellers shall not designate as a Maximum Emergency offer any portion of their ICAP committed as a Base Capacity Resource during the months of June through September when PJM has issued a Hot Weather Alert or declared an Emergency Action, or committed as a Capacity Performance Resource at any time during the Delivery Year when PJM has issued a Hot Weather Alert, Cold Weather Alert or declared an Emergency Action. Any offer not designated as a Maximum Emergency ~~O~~offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency ~~O~~offers outside of the conditions stipulated above and 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, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, 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 hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all Generation Capacity Resources; and

ix) Shall not exceed an energy offer price of $1,000/megawatt-hour, plus the applicable Primary Reserve Penalty Factor, minus $1.00, for all Economic Load Response Resources;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus the applicable Primary Reserve Penalty Factor, minus $1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus [the applicable Primary Reserve Penalty Factor divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, $1,100/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt 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. 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 per MWh 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 $\$/\Delta MW$) 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 and no-load fees, 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 offer by a Market Seller of a Generation Capacity Resource 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 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. 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. The offer must equal or exceed 0.1 megawatts, and the offer 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. 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).

(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 MW 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, no-load 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.

(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 and no-load fees, 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 and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

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 or no-load fees.

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 dispatch 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 dispatch 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 12:00 p.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) Not earlier than 4:00 p.m. 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 4:00 p.m. to 6:00 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 any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. 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 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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 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 12:00 noon 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 dynamically scheduled 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. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited 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.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. 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), 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. Market Sellers shall not designate as a Maximum Emergency offer any portion of their ICAP committed as a Base Capacity Resource during the months of June through September when PJM has issued a Hot Weather Alert or declared an Emergency Action, or committed as a Capacity Performance Resource at any time during the Delivery Year when PJM has issued a Hot Weather Alert, Cold Weather Alert or declared an Emergency Action.* Any offer not designated as a Maximum Emergency *o*ffer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers *outside of the conditions stipulated above and* 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, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, 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 hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, *unless the resource's cost-based offer, calculated in accordance with Schedule 2 of the Operating Agreement, section 6.4.2 of Attachment K- Appendix of the Tariff and the parallel provisions of Schedule 1 of the Operating Agreement, and PJM Manual 15, exceeds $1,000/megawatt-hour, in which case the resource may submit an offer no greater than an amount equal to that cost-based offer which shall not exceed $1,800/megawatt-hour*; and

ix) Shall not exceed an energy offer price of $1,000/megawatt-hour, plus the applicable ~~Primary~~ Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00, for all Economic Load Response Resources;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus the applicable ~~Primary~~ Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus [the applicable ~~Primary~~ Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, $1,100/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt 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. 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 per MWh 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 and no-load fees, 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 offer by a Market Seller of a Generation Capacity Resource 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 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. 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. The offer must equal or exceed 0.1 megawatts, and the offer 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. 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).

(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 MW 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, no-load 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.

(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 and no-load fees, 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 and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

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 or no-load fees.

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 dispatch 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 dispatch 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 12:00 p.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) Not earlier than 4:00 p.m. 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 4:00 p.m. to 6:00 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 any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. 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 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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 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 12:00 noon 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 dynamically scheduled 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. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited 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.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. 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), 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. ~~Market Sellers shall not designate as a Maximum Emergency offer any portion of their ICAP committed as a Base Capacity Resource during the months of June through September when PJM has issued a Hot Weather Alert or declared an Emergency Action, or committed as a Capacity Performance Resource at any time during the Delivery Year when PJM has issued a Hot Weather Alert, Cold Weather Alert or declared an Emergency Action.~~ 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 ~~outside of the conditions stipulated above and~~ 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, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, 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 hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all Generation Capacity Resources; and

ix) Shall not exceed an energy offer price of $1,000/megawatt-hour, plus the applicable Primary Reserve Penalty Factor, minus $1.00, for all Economic Load Response Resources;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus the applicable Primary Reserve Penalty Factor, minus $1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus [the applicable Primary Reserve Penalty Factor divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, $1,100/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt 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. 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 per MWh 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 and no-load fees, 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 offer by a Market Seller of a Generation Capacity Resource 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 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. 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. The offer must equal or exceed 0.1 megawatts, and the offer 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. 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).

(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 MW 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, no-load 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.

(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 and no-load fees, 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 and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

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 or no-load fees.

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 dispatch 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 dispatch 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 12:00 p.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) Not earlier than 4:00 p.m. 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 4:00 p.m. to 6:00 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 any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. 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 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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.

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3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

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

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

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer

in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

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

historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

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

Energy Score = 1 - 1/n ∑ Abs (Error);

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

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

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

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

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

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

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

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

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to

the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

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

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

A Generation Capacity Resource that operates outside of its physically determined parameter limitations due to external requirements such as fuel delivery arrangements, for example, will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection.

Consistent with Sections 1.10.1 and 6.6 hereof, resources with notification or start up times greater than one day that are committed by the Office of the Interconnection will not receive Operating Reserve Credits nor 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.

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any

Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

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

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

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

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

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

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

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

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

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

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

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

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

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

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

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

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

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource’s day-ahead schedules.

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

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

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

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

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

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

where:

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

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

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

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

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

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

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

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

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

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

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

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

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

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual

reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

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

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of

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

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

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

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

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

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

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

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

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

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized

Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

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

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the

Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

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

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource’s output necessary to follow the Office of the Interconnection’s signals and instructions from the generation resource’s expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the

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

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

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

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

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

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

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

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

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the

Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

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

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

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

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

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the

Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

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

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer.

Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

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

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

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer

in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

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

historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

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

Energy Score = 1 - 1/n ∑ Abs (Error);

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

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

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

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

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

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

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

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

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to

the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

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

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

A Generation Capacity Resource that operates outside of its physically determined parameter limitations due to external requirements such as fuel delivery arrangements, for example, will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection.

Consistent with Sections 1.10.1 and 6.6 hereof, resources with notification or start up times greater than one day that are committed by the Office of the Interconnection will not receive Operating Reserve Credits nor 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.

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any

Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

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

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

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

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

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

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

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

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

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

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

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

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

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

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

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

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

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price *for a market-based offer* is greater than $1,000/MWh *and greater than the Market Seller's lowest available and applicable cost-based offer*, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

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

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

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

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

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

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

where:

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

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

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

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

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

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

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

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

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

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

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

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

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

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual

reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

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

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

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

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

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

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

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of

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

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

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

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

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

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource greater than $1,800/megawatt-hour, determined in accordance with Schedule 2 of the Operating Agreement and PJM Manual 15 and that would otherwise be included in a cost-based offer, will be eligible to receive credit for Operating Reserves at a level consistent with the difference between the resource's calculated costs above $1,800/megawatt-hour and the overall energy offer cap of $1,800/megawatt-hour. Before receiving any credit for Operating Reserves, all relevant documentation demonstrating the calculation of costs greater than $1,800/megawatt-hour must be submitted to the Office of the Interconnection and the Market Monitoring Unit. The Office of the Interconnection must approve any Operating Reserves credits paid to a Market Seller under this subsection (r). Market Sellers requesting costs under this subsection (r) shall not be eligible to include an adder specified in section 6.4.2 hereof in its cost-based offers for the generation resource.

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market

Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the O~~o~~perating D~~d~~ay. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve ~~r~~Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the ~~Synchronized~~applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the ~~Synchronized~~ Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement ~~and the Primary Reserve Penalty Factor~~ for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the ~~Primary~~ Reserve Penalty Factors for the Primary Reserve Requirement and the ~~Synchronized Reserve Penalty Factor~~Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The ~~Synchronized~~ Reserve Penalty Factors for the Synchronized Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

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

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

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

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

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

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the O~~o~~perating D~~d~~ay. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve R~~r~~equirement or Extended Primary Reserve Requirement. When the Primary Reserve R~~r~~equirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the ~~Primary~~ applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone~~will be determined as the Primary Reserve Penalty Factor~~. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the ~~Primary~~ Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The ~~Primary~~ Reserve Penalty Factors for the Primary Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

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

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

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

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

~~(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's~~

~~load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).~~

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

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

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

Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

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

3.2.3B Reactive Services.

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

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

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

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

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

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

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

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

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

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

where UB - URTLMP shall not be negative.

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

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

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

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

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

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer

in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

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

historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

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

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

$$\text{Error} = \text{Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and}$$

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

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

$$\text{Accuracy Score} = \max((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

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

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

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

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

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

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

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

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

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

A Generation Capacity Resource that operates outside of its physically determined parameter limitations due to external requirements such as fuel delivery arrangements, for example, will *not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection.*

Consistent with Sections 1.10.1 and 6.6 hereof, resources with notification or start up times greater than one day that are committed by the Office of the Interconnection will not receive Operating Reserve Credits nor 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.

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the applicable offer for energy on which the generating unit was committed in the Real-time Energy Market, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

The deviation of the generating unit's output is equal to the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

~~{(LMPDMW - AG) x (URTLMP – UB)}, where:~~

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

~~AG equals the actual hourly integrated output of the unit;~~

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

~~UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and~~

~~where URTLMP - UB shall not be negative.~~

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

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

(ii) for each hour a~~if the~~ unit is scheduled to produce energy in the D~~d~~ay-ahead Energy M~~m~~arket, but the unit is not called on by the Office of the Interconnection ~~PJM~~ and does not operate in real time, then the Market Seller shall be credited ~~hourly~~ in an amount equal to the higher of:

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

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

~~(i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:~~

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

~~UDALMP equals the day-ahead LMP at the unit's bus;~~

~~DAG equals the day-ahead scheduled unit output for the hour;~~

~~UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and~~

~~where URTLMP - UDALMP and URTLMP – UB shall not be negative.~~

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

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

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

The deviation of the generating unit's output is equal to the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed.   For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

~~{(LMPDMW - AG) x (URTLMP – UB)}, where:~~

~~LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;~~

~~AG equals the actual hourly integrated output of the unit;~~

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

~~UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and~~

~~where URTLMP – UB shall not be negative.~~

~~In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.~~

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

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

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

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

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

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

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

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

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

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

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

provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for

Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

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

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

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

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

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

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

where:

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

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

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

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

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

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

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

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

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

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

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

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve

Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Synchronized Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

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

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier

2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized

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

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

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

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended

Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Primary Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

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

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

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

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

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

(d) The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead

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

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

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

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

3.2.3B Reactive Services.

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

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

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

The deviation of the generating unit's output is equal to the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.
~~{(LMPDMW - AG) x (URTLMP - UB)}~~

~~where:~~

~~LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated~~

~~real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;~~

~~AG equals the actual hourly integrated output of the unit;~~

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

~~UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and~~

~~where URTLMP - UB shall not be negative.~~

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

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

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

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

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

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

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

where UB - URTLMP shall not be negative.

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

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

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve.

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

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

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

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer

in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

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

historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

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

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

$$\text{Error} = \text{Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal))}; \text{ and}$$

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

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

$$\text{Accuracy Score} = \max\left((\text{Delay Score}) + (\text{Correlation Score})\right) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

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

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

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

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

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

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to

the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

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

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

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

~~Consistent with Sections 1.10.1 and 6.6 hereof, resources with notification or start up times greater than one day that are committed by the Office of the Interconnection will not receive Operating Reserve Credits nor 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.~~

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

> (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.
>
> (ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be

credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

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

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

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

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

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and
>
> where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

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

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

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

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

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

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

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

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_t = {}^{(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1})}\!\big/_{(\mathbf{UDSLAtime}_{t-1})}$$

$$\mathbf{RL\_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_t * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh - Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating

Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve

Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized

Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 ~~——~~ Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in an hour in excess of the Non-Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

OATT ATT K-Appendix Section 5.2

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5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Offer and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right or had an Up-to Congestion Transaction that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for a path at or near the path of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Offer, Decrement Bid or Up-to Congestion Transaction is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated

using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an unanticipated event outside the control of PJM~~force majeure~~ that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, “mitigation”) rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer’s share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall

assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Offer and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right or had an Up-to Congestion Transaction that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for a path at or near the path of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Offer, Decrement Bid or Up-to Congestion Transaction is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified ~~monthly~~ period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified ~~monthly~~ period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated

using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an *unanticipated* event *outside the control* of *PJM* that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, “mitigation”) rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer’s share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall

assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

OATT Attachment Q

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ATTACHMENT Q

PJM CREDIT POLICY

POLICY STATEMENT:

It is the policy of PJM Interconnection, LLC ("PJM") that prior to an entity participating in the PJM Markets, or in order to take Transmission Service, the entity must demonstrate its ability to meet PJMSettlement's credit requirements.

Prior to becoming a Market Participant, Transmission Customer, and/or Member of PJM, PJMSettlement must accept and approve a Credit Application (including Credit Agreement) from such entity and establish a Working Credit Limit with PJMSettlement. PJMSettlement shall approve or deny an accepted Credit Application on the basis of a complete credit evaluation including, but not be limited to, a review of financial statements, rating agency reports, and other pertinent indicators of credit strength.

POLICY INTENT:

This credit policy describes requirements for: (1) the establishment and maintenance of credit by Market Participants, Transmission Customers, and entities seeking either such status (collectively "Participants"), pursuant to one or more of the Agreements, and (2) forms of security that will be deemed acceptable (hereinafter the "Financial Security") in the event that the Participant does not satisfy the financial or other requirements to establish Unsecured Credit.

This policy also sets forth the credit limitations that will be imposed on Participants in order to minimize the possibility of failure of payment for services rendered pursuant to the Agreements, and conditions that will be considered an event of default pursuant to this policy and the Agreements.

These credit rules may establish certain set-asides of credit for designated purposes (such as for FTR or RPM activity). Such set-asides shall be construed to be applicable to calculation of credit requirements only, and shall not restrict PJMSettlement's ability to apply such designated credit to any obligation(s) in case of a default.

PJMSettlement may post on PJM's web site, and may reference on OASIS, a supplementary document which contains additional business practices (such as algorithms for credit scoring) that are not included in this document. Changes to the supplementary document will be subject to stakeholder review and comment prior to implementation. PJMSettlement may specify a required compliance date, not less than 15 days from notification, by which time all Participants must comply with provisions that have been revised in the supplementary document.

APPLICABILITY:

This policy applies to all Participants.

IMPLEMENTATION:

I. CREDIT EVALUATION

Each Participant will be subject to a complete credit evaluation in order for PJMSettlement to determine creditworthiness and to establish an **Unsecured Credit Allowance**, if applicable; provided, however, that a Participant need not provide the information specified in section I.A or I.B if it notifies PJMSettlement in writing that it does not seek any Unsecured Credit Allowance. PJMSettlement will identify any necessary Financial Security requirements and establish a Working Credit Limit for each Participant. In addition, PJMSettlement will perform follow-up credit evaluations on at least an annual basis.

If a **Corporate Guaranty** is being utilized to establish credit for a Participant, the guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

PJMSettlement will provide a Participant, upon request, with a written explanation for any change in credit levels or collateral requirements. PJMSettlement will provide such explanation within ten Business Days.

If a Participant believes that either its level of unsecured credit or its collateral requirement has been incorrectly determined, according to this credit policy, then the Participant may send a request for reconsideration in writing to PJMSettlement. Such a request should include:

- A citation to the applicable section(s) of the PJMSettlement credit policy along with an explanation of how the respective provisions of the credit policy were not carried out in the determination as made

- A calculation of what the Participant believes should be the correct credit level or collateral requirement, according to terms of the credit policy

PJMSettlement will reconsider the determination and will provide a written response as promptly as practical, but no longer than ten Business Days of receipt of the request. If the Participant still feels that the determination is incorrect, then the Participant may contest that determination. Such contest should be in written form, addressed to PJMSettlement, and should contain:

- ♦ A complete copy of the Participant’s earlier request for reconsideration, including citations and calculations

- ♦ A copy of PJMSettlement’s written response to its request for reconsideration

- ♦ An explanation of why it believes that the determination still does not comply with the credit policy

PJMSettlement will investigate and will respond to the Participant with a final determination on the matter as promptly as practical, but no longer than 20 Business Days.

Neither requesting reconsideration nor contesting the determination following such request shall relieve or delay Participant's responsibility to comply with all provisions of this credit policy.

A. Initial Credit Evaluation

In completing the initial credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit with its application audited financial statements for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the Participant, if shorter. All financial and related information considered for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement.

The information should include, but not be limited to, the following:

a. If publicly traded:
   - i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
   - ii. Form 8-K reports disclosing Material changes, if any.

b. If privately held:
   - i. Management's Discussion & Analysis
   - ii. Report of Independent Accountants
   - iii. Financial Statements, including:
     - Balance Sheet
     - Income Statement
     - Statement of Cash Flows
     - Statement of Stockholder's Equity
   - iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) References

PJMSettlement may request Participants to provide with their applications at least one (1) bank and three (3) utility credit references. In the case where a Participant does not have the required utility references, trade payable vendor references may be substituted.

4) Litigation, Commitments and Contingencies

Each Participant is also required to provide with its application information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJMSettlement or are applying for membership with PJMSettlement. Each Participant is also required to disclose the existence of any ongoing investigations by the Securities and Exchange Commission (“SEC”), Federal Energy Regulatory Commission (“FERC”), Commodity Futures Trading Commission (“CFTC”), or any other governing, regulatory, or standards body. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

B. Ongoing Credit Evaluation

On at least an annual basis, PJMSettlement will perform follow-up credit evaluations on all Participants. In completing the credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor’s, Moody’s Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit audited annual financial statements as soon as they become available and no later than 120 days after fiscal year end. Each Participant is also required to provide PJMSettlement with quarterly financial statements promptly upon their issuance, but no later than 60 days after the end of each quarter. All financial and related information considered

for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement. If financial statements are not provided within the timeframe required, the Participant may not be granted an Unsecured Credit Allowance.

The information should include, but not be limited to, the following:

a. If publicly traded:
   i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
   ii. Form 8-K reports disclosing Material changes, if any, immediately upon issuance.

b. If privately held:
   i. Management's Discussion & Analysis
   ii. Report of Independent Accountants
   iii. Financial Statements, including:
      - Balance Sheet
      - Income Statement
      - Statement of Cash Flows
      - Statement of Stockholder's Equity
   iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) Material Changes

Each Participant is responsible for informing PJMSettlement immediately, in writing, of any Material change in its financial condition. However, PJMSettlement may also independently establish from available information that a Participant has experienced a Material change in its financial condition without regard to whether such Participant has informed PJMSettlement of the same.

For the purpose of this policy, a Material change in financial condition may include, but not be limited to, any of the following:

a. a downgrade of any debt rating by any rating agency;
b. being placed on a credit watch with negative implications by any rating agency;
c. a bankruptcy filing;
d. insolvency;

e. a report of a quarterly or annual loss or a decline in earnings of ten percent or more compared to the prior period;

f. restatement of prior financial statements;

g. the resignation of key officer(s);

h. the filing of a lawsuit that could adversely impact any current or future financial results by ten percent or more;

i. financial default in another organized wholesale electric market futures exchange or clearing house;

j. revocation of a license or other authority by any Federal or State regulatory agency; where such license or authority is necessary or important to the Participants continued business for example, FERC market-based rate authority, or State license to serve retail load; or

k. a significant change in credit default spreads, market capitalization, or other market-based risk measurement criteria, such as a recent increase in Moody's KMV Expected Default Frequency (EDF^{tm}) that is noticeably greater than the increase in its peers' EDF^{tm} rates, or a collateral default swap (CDS) premium normally associated with an entity rated lower than investment grade.

If PJMSettlement determines that a Material change in the financial condition of the Participant has occurred, it may require the Participant to provide Financial Security within two Business Days, in an amount and form approved by PJMSettlement. If the Participant fails to provide the required Financial Security, the Participant shall be in default under this credit policy.

In the event that PJMSettlement determines that a Material change in the financial condition of a Participant warrants a requirement to provide Financial Security, PJMSettlement shall provide the Participant with a written explanation of why such determination was made. However, under no circumstances shall the requirement that a Participant provide the requisite Financial Security be deferred pending the issuance of such written explanation.

4) Litigation, Commitments, and Contingencies

Each Participant is also required to provide information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon initiation or change or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJM or are applying for membership within PJM. Each Participant is also required to disclose the existence of any ongoing investigations by the SEC, FERC, CFTC or any other governing, regulatory, or standards body. These disclosures shall be made upon initiation or change, or as requested by PJMSettlement.

C. Corporate Guaranty

If a Corporate Guaranty is being utilized to establish credit for a Participant, the Guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

An irrevocable and unconditional Corporate Guaranty may be utilized as part of the credit evaluation process, but will not be considered a form of Financial Security. The Corporate Guaranty will be considered a transfer of credit from the Guarantor to the Participant. The Corporate Guaranty must guarantee the (i) full and prompt payment of all amounts payable by the Participant under the Agreements, and (ii) performance by the Participant under this policy.

The Corporate Guaranty should clearly state the identities of the “Guarantor,” “Beneficiary” (PJMSettlement) and “Obligor” (Participant). The Corporate Guaranty must be signed by an officer of the Guarantor, and must demonstrate that it is duly authorized in a manner acceptable to PJMSettlement. Such demonstration may include either a Corporate Seal on the Guaranty itself, or an accompanying executed and sealed Secretary’s Certificate noting that the Guarantor was duly authorized to provide such Corporate Guaranty and that the person signing the Corporate Guaranty is duly authorized, or other manner acceptable to PJMSettlement.

A Participant supplying a Corporate Guaranty must provide the same information regarding the Guarantor as is required in the “Initial Credit Evaluation” §I.A. and the “Ongoing Evaluation” §I.B. of this policy, including providing the Rating Agency Reports, Financial Statements and Related Information, References, Litigation Commitments and Contingencies, and Other Disclosures. A Participant supplying a Foreign or Canadian Guaranty must also satisfy the requirements of §I.C.1 or §I.C.2, as appropriate.

If there is a Material change in the financial condition of the Guarantor or if the Corporate Guaranty comes within 30 days of expiring without renewal, the Participant will be required to provide Financial Security either in the form of a cash deposit or a letter of credit. Failure to provide the required Financial Security within two Business Days after request by PJMSettlement will constitute an event of default under this credit policy. A Participant may request PJMSettlement to perform a credit evaluation in order to determine creditworthiness and to establish an Unsecured Credit Allowance, if applicable. If PJMSettlement determines that a Participant does qualify for a sufficient Unsecured Credit Allowance, then Financial Security will not be required.

The PJMSettlement Credit Application contains an acceptable form of Corporate Guaranty that should be utilized by a Participant choosing to establish its credit with a Corporate Guaranty. If the Corporate Guaranty varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a Corporate Guaranty and meeting the policy provisions are the responsibility of the Participant.

1) Foreign Guaranties

A Foreign Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in a country other than the United States or Canada. The entity providing a Foreign Guaranty on behalf of a Participant is a Foreign Guarantor. A Participant may provide a Foreign

Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met:

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Foreign Guaranty at any time, including for material adverse circumstances or occurrences.

a. A Foreign Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.
   iv. Will not be accepted towards a Participant's Unsecured Credit Allowance for more than the following limits, depending on the Foreign Guarantor's credit rating:

Rating of Foreign Guarantor	Maximum Accepted Guaranty if Country Rating is AAA	Maximum Accepted Guaranty if Country Rating is AA+
A- and above	USD50,000,000	USD30,000,000
BBB+	USD30,000,000	USD20,000,000
BBB	USD10,000,000	USD10,000,000
BBB- or below	USD 0	USD 0

   v. May not exceed 50% of the Participant's total credit, if the Foreign Grantor is rated less than BBB+.

b. A Foreign Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Foreign Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must have a Senior Unsecured (or equivalent, in PJMSettlement's sole discretion) rating of BBB (one notch above BBB-) or greater by any and all agencies that provide rating coverage of the entity.
   vi. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance

vii. Must provide a Secretary's Certificate certifying the adoption of Corporate Resolutions:
    1. Authorizing and approving the Guaranty; and
    2. Authorizing the Officers to execute and deliver the Guaranty on behalf of the Guarantor.

viii. Must be domiciled in a country with a minimum long-term sovereign (or equivalent) rating of AA+/Aa1, with the following conditions:
    1. Sovereign ratings must be available from at least two rating agencies acceptable to PJMSettlement (e.g. S&P, Moody's, Fitch, DBRS).
    2. Each agency's sovereign rating for the domicile will be considered to be the lowest of: country ceiling, senior unsecured government debt, long-term foreign currency sovereign rating, long-term local currency sovereign rating, or other equivalent measures, at PJMSettlement's sole discretion.
    3. Whether ratings are available from two or three agencies, the lowest of the two or three will be used.

ix. Must be domiciled in a country that recognizes and enforces judgments of US courts.

x. Must demonstrate financial commitment to activity in the United States as evidenced by one of the following:
    1. American Depository Receipts (ADR) are traded on the New York Stock Exchange, American Stock Exchange, or NASDAQ.
    2. Equity ownership worth over USD100,000,000 in the wholly-owned or majority owned subsidiaries in the United States.

xi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this credit policy.

xii. Must pay for all expenses incurred by PJMSettlement related to reviewing and accepting a foreign guaranty beyond nominal in-house credit and legal review.

xiii. Must, at its own cost, provide PJMSettlement with independent legal opinion from an attorney/solicitor of PJMSettlement's choosing and licensed to practice law in the United States and/or Guarantor's domicile, in form and substance acceptable to PJMSettlement in its sole discretion, confirming the enforceability of the Foreign Guaranty, the Guarantor's legal authorization to grant the Guaranty, the conformance of the Guaranty, Guarantor, and Guarantor's domicile to all of these requirements, and such other matters as PJMSettlement may require in its sole discretion.

2) Canadian Guaranties

A Canadian Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in Canada and satisfies all of the provisions below. The entity providing a Canadian Guaranty on behalf of a Participant is a Canadian Guarantor. A Participant may provide a Canadian Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met.

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Canadian Guaranty at any time for reasonable cause, including adverse material circumstances.

a. A Canadian Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.

b. A Canadian Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Canadian Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance.

   vi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Credit Policy.

Ia. MINIMUM PARTICIPATION REQUIREMENTS

A. PJM Market Participation Eligibility Requirements

To be eligible to transact in PJM Markets, a Market Participant must demonstrate in accordance with the Risk Management and Verification processes set forth below that it qualifies in one of the following ways:

1. an "appropriate person," as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act, or;

2. an "eligible contract participant," as that term is defined in Section 1a(18), or successor provision, of the Commodity Exchange Act, or;

3. a business entity or person who is in the business of: (1) generating, transmitting, or distributing electric energy, or (2) providing electric energy services that are necessary to support the reliable operation of the transmission system, or;

4. a Market Participant seeking eligibility as an "appropriate person" providing an unlimited Corporate Guaranty in a form acceptable to PJMSettlement as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty, or;

5. a Market Participant providing a letter of credit of at least $5 million to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJMSettlement.

If, at any time, a Market Participant cannot meet the eligibility requirements set forth above, it shall immediately notify PJMSettlement and immediately cease conducting transactions in the PJM Markets. PJMSettlement shall terminate a Market Participant's transaction rights in the PJM Markets if, at any time, it becomes aware that the Market Participant does not meet the minimum eligibility requirements set forth above.

In the event that a Market Participant is no longer able to demonstrate it meets the minimum eligibility requirements set forth above, and possesses, obtains or has rights to possess or obtain, any open or forward positions in PJM's Markets, PJMSettlement may take any such action it deems necessary with respect to such open or forward positions, including, but not limited to, liquidation, transfer, assignment or sale; provided, however, that the Market Participant will, notwithstanding its ineligibility to participate in the PJM Markets, be entitled to any positive market value of those positions, net of any obligations due and owing to PJM and/or PJMSettlement.

B. Risk Management and Verification

All Participants shall provide to PJMSettlement an executed copy of the annual certification set forth in Appendix 1 to this Attachment Q. This certification shall be provided before an entity is eligible to participate in the PJM Markets and shall be initially submitted to PJMSettlement together with the entity's Credit Application. Thereafter, it shall be submitted each calendar year by all Participants during a period beginning on January 1 and ending April 30, except that new Participants who became eligible to participate in PJM markets during the period of January through April shall not be required to resubmit such certification until the following calendar year. Except for certain FTR Participants (discussed below) or in cases of manifest error, PJMSettlement will accept such certifications as a matter of course and Participants will not need further notice from PJMSettlement before commencing or maintaining their eligibility to participate in PJM markets. A Participant that fails to provide its annual certification by April 30 shall be ineligible to transact in the PJM markets and PJM will disable the Participant's access to the PJM markets until such time as PJMSettlement receives the Participant's certification.

Participants acknowledge and understand that the annual certification constitutes a representation upon which PJMSettlement will rely. Such representation is additionally made under the PJM Tariff, filed with and accepted by FERC, and any inaccurate or incomplete statement may subject the Participant to action by FERC. Failure to comply with any of the criteria or

requirements listed herein or in the certification may result in suspension of a Participant's transaction rights in the PJM markets.

Certain FTR Participants (those providing representations found in paragraph 3.b of the annual certification set forth in Appendix 1 to this Attachment Q) are additionally required to submit to PJMSettlement (at the time they make their annual certification) a copy of their current governing risk control policies, procedures and controls applicable to their FTR trading activities, except that if no substantive changes have been made to such policies, practices and/or controls applicable to their FTR trading activities, they may instead submit to PJMSettlement a certification stating that no changes have been made. PJMSettlement will review such documentation to verify that it appears generally to conform to prudent risk management practices for entities trading in FTR-type markets. If principles or best practices relating to risk management in FTR-type markets are published, as may be modified from time to time, by a third-party industry association, such as the Committee of Chief Risk Officers, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the fundamental sufficiency of the FTR Participant's risk controls. Those FTR Participants subject to this provision shall make a one-time payment of $1,000.00 to PJMSettlement to cover costs associated with review and verification. Thereafter, if such FTR Participant's risk policies, procedures and controls applicable to its FTR trading activities change substantively, it shall submit such modified documentation, without charge, to PJMSettlement for review and verification at the time it makes its annual certification. Such FTR Participant's continued eligibility to participate in the PJM FTR markets is conditioned on PJMSettlement notifying such FTR Participant that its annual certification, including the submission of its risk policies, procedures and controls, has been accepted by PJMSettlement. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph, however, in all circumstances, PJMSettlement and any third-party it may retain will treat as confidential the documentation provided by an FTR Participant under this paragraph, consistent with the applicable provisions of PJM's Operating Agreement.

An FTR Participant that makes the representation in paragraph 3.a of the annual certification understand that PJMSettlement, given the visibility it has over a Participant's overall market activity in performing billing and settlement functions, may at any time request the FTR Participant provide additional information demonstrating that it is in fact eligible to make the representation in paragraph 3.a of the annual certification. If such additional information is not provided or does not, in PJMSettlement's judgment, demonstrate eligibility to make the representation in paragraph 3.a of the annual certification, PJMSettlement will require the FTR Participant to instead make the representations required in paragraph 3.b of the annual certification, including representing that it has submitted a copy of its current governing risk control policies, procedures and controls applicable to its FTR trading activities. If the FTR Participant cannot or does not make those representations as required in paragraph 3.b of the annual certification, then PJM will terminate the FTR Participant's rights to purchase FTRs in the FTR market and may terminate the FTR Participant's rights to sell FTRs in the PJM FTR market.

PJMSettlement shall also conduct a periodic compliance verification process to review and verify, as applicable, Participants’ risk management policies, practices, and procedures pertaining to the Participants’ activities in the PJM markets. Such review shall include verification that:

1. The risk management framework is documented in a risk policy addressing market, credit and liquidity risks.
2. The Participant maintains an organizational structure with clearly defined roles and responsibilities that clearly segregates trading and risk management functions.
3. There is clarity of authority specifying the types of transactions into which traders are allowed to enter.
4. The Participant has requirements that traders have adequate training relative to their authority in the systems and PJM markets in which they transact.
5. As appropriate, risk limits are in place to control risk exposures.
6. Reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization.
7. Processes are in place for qualified independent review of trading activities.
8. As appropriate, there is periodic valuation or mark-to-market of risk positions.

If principles or best practices relating to risk management in PJM-type markets are published, as may be modified from time to time, by a third-party industry association, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the sufficiency of the Participant’s risk controls. PJMSettlement may select Participants for review on a random basis and/or based on identified risk factors such as, but not limited to, the PJM markets in which the Participant is transacting, the magnitude of the Participant’s transactions in the PJM markets, or the volume of the Participant’s open positions in the PJM markets. Those Participants notified by PJMSettlement that they have been selected for review shall, upon 14 calendar days notice, provide a copy of their current governing risk control policies, procedures and controls applicable to their PJM market activities and shall also provide such further information or documentation pertaining to the Participants' activities in the PJM markets as PJMSettlement may reasonably request. Participants selected for risk management verification through a random process and satisfactorily verified by PJMSettlement shall be excluded from such verification process based on a random selection for the subsequent two years. PJMSettlement shall annually randomly select for review no more than 20% of the Participants in each member sector.

Each selected Participant’s continued eligibility to participate in the PJM markets is conditioned upon PJMSettlement notifying the Participant of successful completion of PJMSettlement’s verification of the Participant’s risk management policies, practices and procedures, as discussed

herein. However, if PJMSettlement notifies the Participant in writing that it could not successfully complete the verification process, PJMSettlement shall allow such Participant 14 calendar days to provide sufficient evidence for verification prior to declaring the Participant as ineligible to continue to participate in PJM's markets, which declaration shall be in writing with an explanation of why PJMSettlement could not complete the verification. If, prior to the expiration of such 14 calendar days, the Participant demonstrates to PJMSettlement that it has filed with the Federal Energy Regulatory Commission an appeal of PJMSettlement's risk management verification determination, then the Participant shall retain its transaction rights, pending the Commission's determination on the Participant's appeal. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph. PJMSettlement and any third party it may retain will treat as confidential the documentation provided by a Participant under this paragraph, consistent with the applicable provisions of the Operating Agreement. If PJMSettlement retains such outside expertise, a Participant may direct in writing that PJMSettlement perform the risk management review and verification for such Participant instead of utilizing a third party, provided however, that employees and contract employees of PJMSettlement and PJM shall not be considered to be such outside expertise or third parties.

Participants are solely responsible for the positions they take and the obligations they assume in PJM markets. PJMSettlement hereby disclaims any and all responsibility to any Participant or PJM Member associated with Participant's submitting or failure to submit its annual certification or PJMSettlement's review and verification of an FTR Participant's risk policies, procedures and controls. Such review and verification is limited to demonstrating basic compliance by an FTR Participant with the representation it makes under paragraph 3.b of its annual certification showing the existence of written policies, procedures and controls to limit its risk in PJM's FTR markets and does not constitute an endorsement of the efficacy of such policies, procedures or controls.

C. Capitalization

In addition to the Annual Certification requirements in Appendix 1 to this Attachment Q, a Participant must demonstrate that it meets the minimum financial requirements appropriate for the PJM market(s) in which it transacts by satisfying either the Minimum Capitalization or the Provision of Collateral requirements listed below:

1. Minimum Capitalization

FTR Participants must demonstrate a tangible net worth in excess of $1 million or tangible assets in excess of $10 million. Other Participants must demonstrate a tangible net worth in excess of $500,000 or tangible assets in excess of $5 million.

a. In either case, consideration of "tangible" assets and net worth shall exclude assets (net of any matching liabilities, assuming the result is a positive value) which PJMSettlement reasonably believes to be restricted, highly risky, or potentially unavailable to settle a claim in the event of default. Examples include, but are not

limited to, restricted assets and Affiliate assets, derivative assets, goodwill, and other intangible assets.

b. Demonstration of “tangible” assets and net worth may be satisfied through presentation of an acceptable Corporate Guaranty, provided that both:

(i) the guarantor is an affiliate company that satisfies the tangible net worth or tangible assets requirements herein, and;

(ii) the Corporate Guaranty is either unlimited or at least $500,000.

If the Corporate Guaranty presented by the Participant to satisfy these Capitalization requirements is limited in value, then the Participant’s resulting Unsecured Credit Allowance shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this Credit Policy, or:

(2) the face value of the Corporate Guaranty, reduced by $500,000 and further reduced by 10%. (For example, a $10.5 million Corporate Guaranty would be reduced first by $500,000 to $10 million and then further reduced 10% more to $9 million. The resulting $9 million would be the Participant’s Unsecured Credit Allowance available through the Corporate Guaranty).

In the event that a Participant provides collateral in addition to a limited Corporate Guaranty to increase its available credit, the value of such collateral shall be reduced by 10%. This reduced value shall be deemed Financial Security and available to satisfy the requirements of this Credit Policy.

Demonstrations of capitalization must be presented in the form of audited financial statements for the Participant’s most recent fiscal year.

2. Provision of Collateral

If a Participant does not demonstrate compliance with its applicable Minimum Capitalization Requirements above, it may still qualify to participate in PJM’s markets by posting additional collateral, subject to the terms and conditions set forth herein.

Any collateral provided by a Participant unable to satisfy the Minimum Capitalization Requirements above will be restricted in the following manner:

i. Collateral provided by FTR Participants shall be reduced by $500,000 and then further reduced by 10%. This reduced amount shall be considered the Financial Security provided by the Participant and available to satisfy requirements of this Credit Policy.

ii. Collateral provided by other Participants that engage in Virtual Transactions or Export Transactions shall be reduced by $200,000 and then further reduced by 10%. This reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

iii. Collateral provided by other Participants that do not engage in Virtual Transactions or Export Transactions shall be reduced by 10%, and this reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

In the event a Participant that satisfies the Minimum Participation Requirements through provision of collateral also provides a Corporate Guaranty to increase its available credit, then the Participant's resulting Unsecured Credit Allowance conveyed through such Guaranty shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this credit policy, or,

(2) the face value of the Guaranty, reduced by 10%.

II. CREDIT ALLOWANCE AND WORKING CREDIT LIMIT

PJMSettlement's credit evaluation process will include calculating a Credit Score for each Participant. The credit score will be utilized to determine a Participant's Unsecured Credit Allowance.

Participants who do not qualify for an Unsecured Credit Allowance will be required to provide Financial Security based on their Peak Market Activity, as provided below.

A corresponding Working Credit Limit will be established based on the Unsecured Credit Allowance and/or the Financial Security provided.

Where Participant of PJM are considered Affiliates, Unsecured Credit Allowances and Working Credit Limits will be established for each individual Participant, subject to an aggregate maximum amount for all Affiliates as provided for in §II.F of this policy.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

A. Credit Score

For participants with credit ratings, a Credit Score will be assigned based on their senior unsecured credit rating and credit watch status as shown in the table below. If an explicit senior unsecured rating is not available, PJMSettlement may impute an equivalent rating from other ratings that are available. For Participants without a credit rating, but who wish to be considered for unsecured Credit, a Credit Score will be generated from PJMSettlement's review and analysis of various factors that are predictors of financial strength and creditworthiness. Key factors in the scoring process include, financial ratios, and years in business. PJMSettlement will consistently apply the measures it uses in determining Credit Scores. The credit scoring methodology details are included in a supplementary document available on OASIS.

Rated Entities Credit Scores

Rating	Score	Score Modifier	
		Credit Watch Negative	Credit Watch Positive
AAA	100	-1.0	0.0
AA+	99	-1.0	0.0
AA	99	-1.0	0.0
AA-	98	-1.0	0.0
A+	97	-1.0	0.0
A	96	-2.0	0.0
A-	93	-3.0	1.0
BBB+	88	-4.0	2.0
BBB	78	-4.0	2.0
BBB-	65	-4.0	2.0
BB+ and below	0	0.0	0.0

B. Unsecured Credit Allowance

PJMSettlement will determine a Participant's Unsecured Credit Allowance based on its Credit Score and the parameters in the table below. The maximum Unsecured Credit Allowance is the lower of:

1) A percentage of the Participant's Tangible Net Worth, as stated in the table below, with the percentage based on the Participant's credit score; and

2) A dollar cap based on the credit score, as stated in the table below:

Credit Score	Tangible Net Worth Factor	Maximum Unsecured Credit Allowance ($ Million)
91-100	2.125 – 2.50%	$50
81-90	1.708 – 2.083%	$42
71-80	1.292 – 1.667%	$33
61-70	0.875 – 1.25%	$7
51-60	0.458 – 0.833%	$0-$2
50 and Under	0%	$0

If a Corporate Guaranty is utilized to establish an Unsecured Credit Allowance for a Participant, the value of a Corporate Guaranty will be the lesser of:

- The limit imposed in the Corporate Guaranty;
- The Unsecured Credit Allowance calculated for the Guarantor; and
- A portion of the Unsecured Credit Allowance calculated for the Guarantor in the case of Affiliated Participants.

PJMSettlement has the right at any time to modify any Unsecured Credit Allowance and/or require additional Financial Security as may be deemed reasonably necessary to support current market activity. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.

PJMSettlement will maintain a posting of each Participant's unsecured Credit Allowance, along with certain other credit related parameters, on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

C. Seller Credit

Participants that have maintained a Net Sell Position for each of the prior 12 months are eligible for Seller Credit, which is an additional form of Unsecured Credit. A Participant's Seller Credit will be equal to sixty percent of the Participant's thirteenth smallest weekly Net Sell Position invoiced in the past 52 weeks.

Each Participant receiving Seller Credit must maintain both its Seller Credit and its Total Net Sell Position equal to or greater than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided.

For Participants receiving Seller Credit, PJMSettlement may forecast the Participant's Total Net Sell Position considering the Participant's current Total Net Sell Position, recent trends in the Participant's Total Net Sell Position, and other information available to PJMSettlement, such as, but not limited to, known generator outages, changes in load responsibility, and bilateral

transactions impacting the Participant. If PJMSettlement's forecast ever indicates that the Participant's Total Net Sell Position may in the future be less than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided, then PJMSettlement may require Financial Security as needed to cover the difference. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.

Any Financial Security required by PJMSettlement pursuant to these provisions for Seller Credit will be returned once the requirement for such Financial Security has ended. Seller Credit may not be conveyed to another entity through use of a guaranty. Seller Credit shall be subject to the cap on available Unsecured Credit set forth in Section II.F.

D. Peak Market Activity and Financial Security Requirement

A PJM Participant or Applicant that has an insufficient Unsecured Credit Allowance to satisfy its Peak Market Activity will be required to provide Financial Security such that its Unsecured Credit Allowance and Financial Security together are equal to its Peak Market Activity in order to secure its transactional activity in the PJM Market.

Peak Market Activity for Participants will be determined semi-annually beginning in the first complete billing week in the months of April and October. Peak Market Activity shall be the greater of the initial Peak Market Activity, as explained below, or the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two, or three week period, ending within a respective semi-annual period. However, Peak Market Activity shall not exceed the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two or three week period in the prior 52 weeks.

Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

The initial Peak Market Activity for Applicants will be determined by PJMSettlement based on a review of an estimate of their transactional activity for all PJM markets and services over the next 52 weeks, which the Applicant shall provide to PJMSettlement.

The initial Peak Market Activity for Participants, calculated at the beginning of each respective semi-annual period, shall be the three-week average of all non-zero invoice totals over the previous 52 weeks. This calculation shall be performed and applied within three business days following the day the invoice is issued for the first full billing week in the current semi-annual period.

Prepayments shall not affect Peak Market Activity unless otherwise agreed to in writing pursuant to this Credit Policy.

All Peak Market Activity calculations shall take into account reductions of invoice values effectuated by early payments which are applied to reduce a Participant's Peak Market Activity

as contemplated by other terms of the Credit Policy; provided that the initial Peak Market Activity shall not be less than the average value calculated using the weeks for which no early payment was made.

A Participant may reduce its Financial Security Requirement by agreeing in writing (in a form acceptable to PJMSettlement) to make additional payments, including prepayments, as and when necessary to ensure that such Participant's Total Net Obligation at no time exceeds such reduced Financial Security Requirement.

PJMSettlement may, at its discretion, adjust a Participant's Financial Security Requirement if PJMSettlement determines that the Peak Market Activity is not representative of such Participant's expected activity, as a consequence of known, measurable, and sustained changes. Such changes may include the loss (without replacement) of short-term load contracts, when such contracts had terms of three months or more and were acquired through state-sponsored retail load programs, but shall not include short-term buying and selling activities.

PJMSettlement may waive the Financial Security Requirement for a Participant that agrees in writing that it shall not, after the date of such agreement, incur obligations under any of the Agreements. Such entity's access to all electronic transaction systems administered by PJM shall be terminated.

PJMSettlement will maintain a posting of each Participant's Financial Security Requirement on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

E. Working Credit Limit

PJMSettlement will establish a Working Credit Limit for each Participant against which its **Total Net Obligation** will be monitored. The Working Credit Limit is defined as 75% of the Financial Security provided to PJMSettlement and/or 75% of the Unsecured Credit Allowance determined by PJMSettlement based on a credit evaluation, as reduced by any applicable credit requirement determinants defined in this policy. A Participant's Total Net Obligation should not exceed its Working Credit Limit.

> Example: After a credit evaluation by PJMSettlement, a Participant is deemed able to support an Unsecured Credit Allowance of $10.0 million. The Participant will be assigned a Working Credit Limit of $8.5 million. PJMSettlement will monitor the Participant's Total Net Obligations against the Working Credit Limit.

A Participant with an Unsecured Credit Allowance may choose to provide Financial Security in order to increase its Working Credit Limit. A Participant with no Unsecured Credit Allowance may also choose to increase its Working Credit Limit by providing Financial Security in an amount greater than its Peak Market Activity.

If a Participant's Total Net Obligation approaches its Working Credit Limit, PJMSettlement may require the Participant to make an advance payment or increase its Financial Security in order to maintain its Total Net Obligation below its Working Credit Limit. Except as explicitly provided

below, advance payments shall not serve to reduce the Participant's Peak Market Activity for the purpose of calculating credit requirements.

> Example: After 10 days, and with 5 days remaining before the bill is due to be paid, a Participant approaches its $4.0 million Working Credit Limit. PJMSettlement may require a prepayment of $2.0 million in order that the Total Net Obligation will not exceed the Working Credit Limit.

If a Participant exceeds its Working Credit Limit or is required to make advance payments more than ten times during a 52-week period, PJMSettlement may require Financial Security in an amount as may be deemed reasonably necessary to support its Total Net Obligation.

A Participant receiving unsecured credit may make early payments up to ten times in a rolling 52-week period in order to reduce its Peak Market Activity for credit requirement purposes. Imputed Peak Market Activity reductions for credit purposes will be applied to the billing period for which the payment was received. Payments used as the basis for such reductions must be received prior to issuance or posting of the invoice for the relevant billing period. The imputed Peak Market Activity reduction attributed to any payment may not exceed the amount of Unsecured Credit for which the Participant is eligible.

F. Credit Limit Setting For Affiliates

If two or more Participants are Affiliates and each is being granted an Unsecured Credit Allowance and a corresponding Working Credit Limit, PJMSettlement will consider the overall creditworthiness of the Affiliated Participants when determining the Unsecured Credit Allowances and Working Credit Limits in order not to grant more Unsecured Credit than the overall corporation could support.

> **Example:** Participants A and B each have a $10.0 million Corporate Guaranty from their common parent, a holding company with an Unsecured Credit Allowance calculation of $12.0 million. PJMSettlement may limit the Unsecured Credit Allowance for each Participant to $6.0 million, so the total Unsecured Credit Allowance does not exceed the corporate total of $12.0 million.

PJMSettlement will work with Affiliated Participants to allocate the total Unsecured Credit Allowance among the Affiliates while assuring that no individual Participant, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. The aggregate Unsecured Credit for a Participant, including Unsecured Credit Allowance granted based on its own creditworthiness and any Unsecured Credit Allowance conveyed through a Guaranty shall not exceed $50 million. The aggregate Unsecured Credit for a group of Affiliates shall not exceed $50 million. A group of Affiliates subject to this cap shall request PJMSettlement to allocate the maximum Unsecured Credit and Working Credit Limit amongst the group, assuring that no individual Participant or common guarantor, shall exceed the Unsecured Credit level appropriate for its credit strength and activity.

G. Working Credit Limit Violations

1) Notification

A Participant is subject to notification when its Total Net Obligation to PJMSettlement approaches the Participant's established Working Credit Limit.

2) Suspension

A Participant that exceeds its Working Credit Limit is subject to suspension from participation in the PJM markets and from scheduling any future Transmission Service unless and until Participant's credit standing is brought within acceptable limits. A Participant will have two Business Days from notification to remedy the situation in a manner deemed acceptable by PJMSettlement. Additionally, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant's ongoing Transmission Service and participation in PJM Markets. Failure to comply with this policy will be considered an event of default under this credit policy.

H. PJM Administrative Charges

Financial Security held by PJMSettlement shall also secure obligations to PJM for PJM administrative charges.

I. Pre-existing Financial Security

PJMSettlement's credit requirements are applicable as of the effective date of the filing on May 5, 2010 by PJM and PJMSettlement of amendments to Attachment Q. Financial Security held by PJM prior to the effective date of such amendments shall be held by PJM for the benefit of PJMSettlement.

III. VIRTUAL TRANSACTION SCREENING

A. Credit and Financial Security

PJMSettlement does not require a Market Participant to establish separate or additional credit for submitting Virtual Transactions. If a Market Participant chooses to establish additional Financial Security and/or Unsecured Credit Allowance in order to increase its Credit Available for Virtual Transactions, the Market Participant's Working Credit Limit for Virtual Transactions shall be increased in accordance with the definition therof. The Financial Security and/or Unsecured Credit Allowance available to increase a Market Participant's Credit Available for Virtual Transactions shall be the amount of Financial Security and/or Unsecured Credit Allowance available after subtracting any credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy, as applicable.

If a Market Participant chooses to provide additional Financial Security in order to increase its **Credit Available for Virtual Transactions PJMSettlement** may establish a reasonable timeframe, not to exceed three months, for which such Financial Security must be maintained. PJMSettlement will not impose such restriction on a deposit unless a Market Participant is

notified prior to making the deposit. Such restriction, if applied, shall be applied to all future deposits by all Market Participants engaging in Virtual Transactions.

A Market Participant wishing to increase its Credit Available for Virtual Transactions by providing additional Financial Security may make the appropriate arrangements with PJMSettlement. PJMSettlement will make a good faith effort to make new Financial Security available as Credit Available for Virtual Transactions as soon as practicable after confirmation of receipt. In any event, however, Financial Security received and confirmed by noon on a business day will be applied (as provided under this policy) to Credit Available for Virtual Transactions no later than 10:00 am on the following business day. Receipt and acceptance of wired funds for cash deposit shall mean actual receipt by PJMSettlement's bank, deposit into PJMSettlement's customer deposit account, and confirmation by PJMSettlement that such wire has been received and deposited. Receipt and acceptance of letters of credit shall mean receipt of the original letter of credit or amendment thereto, and confirmation from PJMSettlement's credit and legal staffs that such letter of credit or amendment thereto conforms to PJMSettlement's requirements, which confirmation shall be made in a reasonable and practicable timeframe. To facilitate this process, bidders wiring funds for the purpose of increasing their Credit Available for Virtual Transactions are advised to specifically notify PJMSettlement that a wire is being sent for such purpose.

B. Virtual Transaction Screening Process

All Virtual Transactions submitted to PJM shall be subject to a credit screen prior to acceptance in the Day-ahead Energy Market auction. The credit screen process will automatically reject Virtual Transactions submitted by the PJM market participant if the participant's Credit Available for Virtual Transactions is exceeded by the **Virtual Credit Exposure** that is calculated based on the participant's submitted Virtual Transactions as described below.

A Participant's Virtual Credit Exposure will be calculated on a daily basis for all Virtual Transactions submitted by the market participant for the next market day using the following equation:

Virtual Credit Exposure = INC and DEC Exposure + Up-to Congestion Exposure
Where:

1) INC and DEC Exposure is calculated as:

(a) ((the total MWh bid or offered, whichever is greater, hourly at each node) x the Nodal Reference Price x 1 day) summed over all nodes and all hours; plus (b) ((the difference between the total bid MWh cleared and total offered MWh cleared hourly at each node) x Nodal Reference Price) summed over all nodes and all hours for the previous cleared Day-ahead Energy Market.

2) Up-to Congestion Exposure is calculated as:

(a) Total MWh bid hourly for each Up-to Congestion Transaction x (price bid – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours; plus (b) Total MWh cleared hourly for each Up-to Congestion Transaction x (cleared price – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours for the previous cleared Day-ahead Energy Market, provided that hours for which the calculation for an Up-to Congestion Transaction is negative, it shall be deemed to have a zero contribution to the sum.

If a Market Participant's Virtual Transactions are rejected as a result of the credit screen process, the Market Participant will be notified via an eMKT error message. A Market Participant whose Virtual Transactions are rejected may alter its Virtual Transactions so that its Virtual Credit Exposure does not exceed its Credit Available forVirtual Transactions, and may resubmit them. Virtual Transactions may be submitted in one or more groups during a day. If one or more groups of Virtual Transactions is submitted and accepted, and a subsequent group of submitted Virtual Transactions causes the total submitted Virtual Transactions to exceed the Virtual Credit Exposure, then only that subsequent set of Virtual Transactions will be rejected. Previously accepted Virtual Transactions will not be affected, though the Market Participant may choose to withdraw them voluntarily.

IV. RELIABILITY PRICING MODEL AUCTION AND PRICE RESPONSIVE DEMAND CREDIT REQUIREMENTS

Settlement during any Delivery Year of cleared positions resulting or expected to result from any Reliability Pricing Model Auction shall be included as appropriate in Peak Market Activity, and the provisions of this Attachment Q shall apply to any such activity and obligations arising therefrom. In addition, the provisions of this section shall apply to any entity seeking to participate in any RPM Auction, to address credit risks unique to such auctions. The provisions of this section also shall apply under certain circumstances to PRD Providers that seek to commit Price Responsive Demand pursuant to the provisions of the Reliability Assurance Agreement.

A. Applicability

A Market Seller seeking to submit a Sell Offer in any Reliability Pricing Model Auction based on any Capacity Resource for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before submitting such Sell Offer. A PRD Provider seeking to commit Price Responsive Demand for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before it may commit the Price Responsive Demand. Credit must be maintained until such risk of non-performance is substantially eliminated, but may be reduced commensurate with the reduction in such risk, as set forth in Section IV.C.

For purposes of this provision, a resource for which there is a materially increased risk of non-performance shall mean: (i) a Planned Generation Capacity Resource; (ii) a Planned Demand Resource or an Energy Efficiency Resource; (iii) a Qualifying Transmission Upgrade; (iv) an existing or Planned Generation Capacity Resource located outside the PJM Region that at the time it is submitted in a Sell Offer has not secured firm transmission service to the border of the

PJM Region sufficient to satisfy the deliverability requirements of the Reliability Assurance Agreement; or (v) Price Responsive Demand to the extent the responsible PRD Provider has not registered PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

B. Reliability Pricing Model Auction and Price Responsive Demand Credit Requirement

Except as provided for Credit-Limited Offers below, for any resource specified in Section IV.A, other than Price Responsive Demand, the credit requirement shall be the RPM Auction Credit Rate, as provided in Section IV.D, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction. For Qualified Transmission Upgrades, the credit requirements shall be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit. The RPM Auction Credit Requirement for each Market Seller shall be the sum of the credit requirements for all such resources to be offered by such Market Seller in the auction or, as applicable, cleared by such Market Seller from the relevant auctions. For Price Responsive Demand specified in section IV.A, the credit requirement shall be based on the Nominal PRD Value (stated in Unforced Capacity terms) times the Price Responsive Demand Credit Rate as set forth in section IV.E.

Except for Credit-Limited Offers, the RPM Auction Credit Requirement for a Market Seller will be reduced for any Delivery Year to the extent less than all of such Market Seller's offers clear in the Base Residual Auction or any Incremental Auction for such Delivery Year. Such reduction shall be proportional to the quantity, in megawatts, that failed to clear in such Delivery Year.

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Seller electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement, in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the Auction Credit Rate resulting from section IV.D.b.; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Seller electing this alternative, the RPM Auction Credit Requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-Limited Offer, and the RPM Auction Credit Requirement subsequent to posting of the results will be the Auction Credit Rate, as provided in Section IV.D.b, c. or d., as applicable, times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The availability and operational details of Credit-Limited Offers shall be as described in the PJM Manuals.

As set forth in Section IV.D, a Market Seller's Auction Credit Requirement shall be determined separately for each Delivery Year.

C. Reduction in Credit Requirement

As specified in Section IV.D, the RPM Auction Credit Rate may be reduced under certain circumstances after the auction has closed.

The Price Responsive Demand credit requirement shall be reduced as and to the extent the PRD Provider registers PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

In addition, the RPM Auction Credit Requirement for a Participant for any given Delivery Year shall be reduced periodically, provided the Participant successfully meets progress milestones that reduce the risk of non-performance, as follows:

a. For Planned Demand Resources and Energy Efficiency Resources, the RPM Auction Credit Requirement will be reduced in direct proportion to the megawatts of such Demand Resource that the Resource Provider qualifies as a Capacity Resource, in accordance with the procedures established under the Reliability Assurance Agreement.

b. For Existing Generation Capacity Resources located outside the PJM Region that have not secured sufficient firm transmission to the border of the PJM Region prior to the auction in which such resource is first offered, the RPM Credit Requirement shall be reduced in direct proportion to the megawatts of firm transmission service secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

c. For Planned Generation Capacity Resources, the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B beginning as of the effective date of an Interconnection Service Agreement, and shall be reduced to zero on the date of commencement of Interconnection Service.

d. For Planned Generation Capacity Resources located outside the PJM Region, the RPM Credit Requirement shall be reduced by 50% once the conditions in both b and c above are met, i.e., the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B when 1) ~~beginning as of~~ the ~~effective date of the~~ equivalent of an Interconnection Service Agreement becomes effective, and 2) ~~when~~ 50% or more megawatts of firm transmission service have been secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement. The RPM Credit Requirement for a Planned Generation Capacity Resource located outside the PJM Region shall be reduced to zero when 1) the resource commences Interconnection Service and 2) 100% of the megawatts of firm transmission service have been secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

e. For Qualifying Transmission Upgrades, the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B beginning as of the effective date of the latest associated Interconnection Service Agreement (or, when a project will have no such agreement, an Upgrade Construction Service Agreement), and shall be reduced to zero on the date the

Qualifying Transmission Upgrade is placed in service. In addition, a Qualifying Transmission Upgrade will be allowed a reduction in its RPM Credit Requirement equal to the amount of collateral currently posted with PJM for the facility construction when the Qualifying Transmission Upgrade meets the following requirements: the Upgrade Construction Service Agreement has been fully executed, the full estimated cost to complete as most recently determined or updated by PJM has been fully paid or collateralized, and all regulatory and other required approvals (except those that must await construction completion) have been obtained. Such reduction in RPM Credit Requirement may not be transferred across different projects.

D. RPM Auction Credit Rate

As set forth in the PJM Manuals, a separate Auction Credit Rate shall be calculated for each Delivery ~~y~~Year prior to each Reliability Pricing Model Auction for such Delivery Year, as follows:

~~For Delivery Years through the Delivery Year that ends on May 31, 2012, the Auction Credit Rate for any resource for a Delivery Year shall be (the greater of $20/MW-day or 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year.~~

~~For Delivery Years beginning with the Delivery Year that commences on June 1, 2012:~~

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the greater of ((A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year.

b. Subsequent to the posting of the results from a Base Residual Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A~~i~~) $20/MW-day or (B~~ii~~) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).

c. For any resource not previously committed for a Delivery Year that seeks to participate in an Incremental Auction, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A~~i~~) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B~~ii~~) 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located or (C~~iii~~) $20 per MW-day) times the number of days in such Delivery Year; and~~.~~

(ii) For Capacity Performance Resources, the (greater of (A) 0.5 times Net Cost of New Entry or (B) $20/MW-day) times the number of days in such Delivery Year.

d. Subsequent to the posting of the results of an Incremental Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For Base Capacity Resources: (the greater of (A~~i~~) $20/MW-day or (B~~ii~~) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year, but no greater than the Auction Credit Rate previously established for such resource's participation in such Incremental Auction pursuant to subsection (c) above) times the number of days in such Delivery Year~~.~~; and

(ii) For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).

E. Price Responsive Demand Credit Rate

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (ii) $20 per MW-day) times the number of days in such Delivery Year;

b. Subsequent to the posting of the results from a Base Residual Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for Price Responsive Demand registered prior to such auction shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the PRD load is located) times the number of days in such Delivery Year times a final price uncertainty factor of 1.05;

c. For any additional Price Responsive Demand that seeks to commit in a Third Incremental Auction in response to a qualifying change in the final LDA load forecast, the Price Responsive Demand Credit Rate shall be the same as the rate for Price Responsive Demand that had cleared in the Base Residual Auction;

d. Subsequent to the posting of the results of the Third Incremental Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for all Price Responsive Demand, shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Final Zonal Capacity Price for the Locational Deliverability Area within which the Price Responsive Demand is located) times the number of days in such Delivery Year, but no greater than the Price Responsive Demand Credit Rate previously established under subsections (a), (b), or (c) of this section for such Delivery Year.

F. RPM Seller Credit - Additional Form of Unsecured Credit for RPM

In addition to the forms of credit specified elsewhere in this Attachment Q, RPM Seller Credit shall be available to Market Sellers, but solely for purposes of satisfying RPM Auction Credit Requirements. If a supplier has a history of being a net seller into PJM markets, on average, over the past 12 months, then PJMSettlement will count as available Unsecured Credit twice the average of that participant's total net monthly PJMSettlement bills over the past 12 months. This RPM Seller Credit shall be subject to the cap on available Unsecured Credit as established in Section II.F.

G. Credit Responsibility for Traded Planned RPM Capacity Resources

PJMSettlement may require that credit and financial responsibility for planned RPM Capacity Resources that are traded remain with the original party (which for these purposes, means the party bearing credit responsibility for the planned RPM Capacity Resource immediately prior to trade) unless the receiving party independently establishes consistent with the PJM credit policy, that it has sufficient credit with PJMSettlement and agrees by providing written notice to PJMSettlement that it will fully assume the credit responsibility associated with the traded planned RPM Capacity Resource.

V. FINANCIAL TRANSMISSION RIGHT AUCTIONS

A. FTR Credit Limit.

PJMSettlement will establish an FTR Credit Limit for each Participant. Participants must maintain their FTR Credit Limit at a level equal to or greater than their FTR Credit Requirement. FTR Credit Limits will be established only by a Participant providing Financial Security.

B. FTR Credit Requirement.

For each Participant with FTR activity, PJMSettlement shall calculate an FTR Credit Requirement based on FTR cost less a discounted historical value. FTR Credit Requirements shall be further adjusted by ARR credits available and by an amount based on portfolio diversification, if applicable. The requirement will be based on individual monthly exposures which are then used to derive a total requirement.

The FTR Credit Requirement shall be calculated by first adding for each month the FTR Monthly Credit Requirement Contribution for each submitted, accepted, and cleared FTR and then subtracting the prorated value of any ARRs held by the Participant for that month. The resulting twelve monthly subtotals represent the expected value of net payments between PJMSettlement and the Participant for FTR activity each month during the Planning Period. Subject to later adjustment by an amount based on portfolio diversification, if applicable, the FTR Credit Requirement shall be the sum of the individual positive monthly subtotals, representing months in which net payments to PJMSettlement are expected.

C. Rejection of FTR Bids.

Bids submitted into an auction will be rejected if the Participant's FTR Credit Requirement including such submitted bids would exceed the Participant's FTR Credit Limit, or if the Participant fails to establish additional credit as required pursuant to provisions related to portfolio diversification.

D. FTR Credit Collateral Returns.

A Market Participant may request from PJMSettlement the return of any collateral no longer required for the FTR auctions. PJMSettlement is permitted to limit the frequency of such requested collateral returns, provided that collateral returns shall be made by PJMSettlement at least once per calendar quarter, if requested by a Market Participant.

E. Credit Responsibility for Traded FTRs.

PJMSettlement may require that credit responsibility associated with an FTR traded within PJM's eFTR system remain with the original party (which for these purposes, means the party bearing credit responsibility for the FTR immediately prior to trade) unless and until the receiving party independently establishes, consistent with the PJM credit policy, sufficient credit with PJMSettlement and agrees through confirmation of the FTR trade within the eFTR system that it will meet in full the credit requirements associated with the traded FTR.

F. Portfolio Diversification.

Subsequent to calculating a tentative cleared solution for an FTR auction (or auction round), PJM shall both:

1. Determine the FTR Portfolio Auction Value, including the tentative cleared solution. Any Participants with such FTR Portfolio Auction Values that are negative shall be deemed FTR Flow Undiversified.

2. Measure the geographic concentration of the FTR Flow Undiversified portfolios by testing such portfolios using a simulation model including, one at a time, each planned transmission outage or other network change which would substantially affect the network for the specific auction period. A list of such planned outages or changes anticipated to be modeled shall be posted prior to commencement of the auction (or auction round). Any FTR Flow Undiversified portfolio that experiences a net reduction in calculated congestion credits as a result of any one or more of such modeled outages or changes shall be deemed FTR Geographically Undiversified.

For portfolios that are FTR Flow Undiversified but not FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to twice the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For Participants with portfolios that are both FTR Flow Undiversified and FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to three times the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For portfolios that are FTR Flow Undiversified in months subsequent to the current planning year, these incremental amounts, calculated on a monthly basis, shall be reduced (but not below zero) by an amount up to 25% of the monthly value of ARR credits that are held by a Participant. Subsequent to the ARR allocation process preceding an annual FTR auction, such ARRs credits shall be reduced to zero for months associated with that ARR allocation process. PJMSettlement may recalculate such ARR credits at any time, but at a minimum shall do so subsequent to each annual FTR auction. If a reduction in such ARR credits at any time increases the amount of credit required for the Participant beyond its credit available for FTR activity, the Participant must increase its credit to eliminate the shortfall.

If the FTR Credit Requirement for any Participant exceeds its credit available for FTRs as a result of these diversification requirements for the tentatively cleared portfolio of FTRs, PJMSettlement shall immediately issue a demand for additional credit, and such demand must be fulfilled before 4:00 p.m. on the business day following the demand. If any Participant does not timely satisfy such demand, PJMSettlement, in coordination with PJM, shall cause the removal that Participant's entire set of bids for that FTR auction (or auction round) and a new cleared solution shall be calculated for the entire auction (or auction round).

If necessary, PJM shall repeat the auction clearing calculation. PJM shall repeat these portfolio diversification calculations subsequent to any such secondary clearing calculation, and PJMSettlement shall require affected Participants to establish additional credit.

G. FTR Administrative Charge Credit Requirement

In addition to any other credit requirements, PJMSettlement may apply a credit requirement to cover the maximum administrative fees that may be charged to a Participant for its bids and offers.

H. Long-Term FTR Credit Recalculation

Long-term FTR Credit Requirement calculations shall be updated annually for known history, consistent with updating of historical values used for FTR Credit Requirement calculations in the annual auctions.

VI. EXPORT TRANSACTION SCREENING

Export Transactions in the Real-time Energy Market shall be subject to Export Transaction Screening. Export Transaction Screening may be performed either for the duration of the entire Export Transaction, or separately for each time interval comprising an Export Transaction. PJM will deny or curtail all or a portion (based on the relevant time interval) of an Export Transaction if that Export Transaction, or portion thereof, would otherwise cause the Market Participant's Export Credit Exposure to exceed its Credit Available for Export Transactions. Export Transaction Screening shall be applied separately for each Operating Day and shall also be applied to each Export Transaction one or more times prior to the market clearing process for each relevant time interval. Export Transaction Screening shall not apply to transactions established directly by and between PJM and a neighboring Balancing Authority for the purpose of maintaining reliability.

A Market Participant's credit exposure for an individual Export Transaction shall be the MWh volume of the Export Transaction for each relevant time interval multiplied by each relevant Export Transaction Price Factor and summed over all relevant time intervals of the Export Transaction.

VII. FORMS OF FINANCIAL SECURITY

Participants that provide Financial Security must provide the security in a PJMSettlement approved form and amount according to the guidelines below.

Financial Security which is no longer required to be maintained under provisions of the Agreements shall be returned at the request of a participant no later than two Business Days following determination by PJMSettlement within a commercially reasonable period of time that such collateral is not required.

Except when an event of default has occurred, a Participant may substitute an approved PJMSettlement form of Financial Security for another PJMSettlement approved form of Financial Security of equal value. The Participant must provide three (3) Business Days notice to PJMSettlement of its intent to substitute the Financial Security. PJMSettlement will release the replaced Financial Security with interest, if applicable, within (3) Business Days of receiving an approved form of substitute Financial Security.

A. Cash Deposit

Cash provided by a Participant as Financial Security will be held in a depository account by PJMSettlement with interest earned at PJMSettlement's overnight bank rate, and accrued to the Participant. PJMSettlement also may establish an array of investment options among which a Participant may choose to invest its cash deposited as Financial Security. Such investment options shall be comprised of high quality debt instruments, as determined by PJMSettlement, and may include obligations issued by the federal government and/or federal government sponsored enterprises. These investment options will reside in accounts held in PJMSettlement's name in a banking or financial institution acceptable to PJMSettlement. Where practicable, PJMSettlement may establish a means for the Participant to communicate directly with the bank or financial institution to permit the Participant to direct certain activity in the PJMSettlement account in which its Financial Security is held. PJMSettlement will establish and publish procedural rules, identifying the investment options and respective discounts in collateral value that will be taken to reflect any liquidation, market and/or credit risk presented by such investments. PJMSettlement has the right to liquidate all or a portion of the account balances at its discretion to satisfy a Participant's Total Net Obligation to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

B. Letter Of Credit

An unconditional, irrevocable standby letter of credit can be utilized to meet the Financial Security requirement. As stated below, the form, substance, and provider of the letter of credit must all be acceptable to PJMSettlement.

- The letter of credit will only be accepted from U.S.-based financial institutions or U.S. branches of foreign financial institutions ("financial institutions") that have a minimum corporate debt rating of "A" by Standard & Poor's or Fitch Ratings, or "A2" from Moody's Investors Service, or an equivalent short term rating from one of these agencies. PJMSettlement will consider the lowest applicable rating to be the rating of the financial institution. If the rating of a financial institution providing a letter of credit is lowered below A/A2 by any rating agency, then PJMSettlement may require the Participant to provide a letter of credit from another financial institution that is rated A/A2 or better, or to provide a cash deposit. If a letter of credit is provided from a U.S. branch of a foreign institution, the U.S. branch must itself comply with the terms of this credit policy, including having its own acceptable credit rating.

- The letter of credit shall state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety (90) days prior written notice from the issuing financial institution. If PJM or PJMSettlement receives notice from the issuing financial institution that the current letter of credit is being cancelled, the Participant will be required to provide evidence, acceptable to PJMSettlement, that such letter of credit will be replaced with appropriate Financial Security, effective as of the cancellation date of the letter of credit, no later than thirty (30) days before the cancellation date of the letter of credit, and no later than ninety (90) days after the notice of cancellation. Failure to do so will constitute a default under this credit policy and one of more of the Agreements.

- The letter of credit must clearly state the full names of the "Issuer", "Account Party" and "Beneficiary" (PJMSettlement), the dollar amount available for drawings, and shall specify that funds will be disbursed upon presentation of the drawing certificate in accordance with the instructions stated in the letter of credit. The letter of credit should specify any statement that is required to be on the drawing certificate, and any other terms and conditions that apply to such drawings.

- The PJMSettlement Credit Application contains an acceptable form of a letter of credit that should be utilized by a Participant choosing to meet its Financial Security requirement with a letter of credit. If the letter of credit varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a letter of credit and meeting the policy provisions are the responsibility of the Participant

- PJMSettlement may accept a letter of credit from a Financial Institution that does not meet the credit standards of this policy provided that the letter of credit has third-party support, in a form acceptable to PJMSettlement, from a financial institution that does meet the credit standards of this policy.

VIII. POLICY BREACH AND EVENTS OF DEFAULT

A Participant will have two Business Days from notification of Breach (including late payment notice) or notification of a Collateral Call to remedy the Breach or satisfy the Collateral Call in a manner deemed acceptable by PJMSettlement. Failure to remedy the Breach or satisfy such Collateral Call within such two Business Days will be considered an event of default. If a Participant fails to meet the requirements of this policy but then remedies the Breach or satisfies a Collateral Call within the two Business Day cure period, then the Participant shall be deemed to have complied with the policy. Any such two Business Day cure period will expire at 4:00 p.m. eastern prevailing time on the final day.

Only one cure period shall apply to a single event giving rise to a breach or default. Application of Financial Security towards a non-payment Breach shall not be considered a satisfactory cure of the Breach if the Participant fails to meet all requirements of this policy after such application.

Failure to comply with this policy (except for the responsibility of a Participant to notify PJMSettlement of a Material change) shall be considered an event of default. Pursuant to § 15.1.3(a) of the Operating Agreement of PJM Interconnection, L.L.C. and § I.7.3 of the PJM Open Access Transmission Tariff, non-compliance with the PJMSettlement credit policy is an event of default under those respective Agreements. In event of default under this credit policy or one or more of the Agreements, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant's ongoing Transmission Service and participation in PJM Markets. PJMSettlement has the right to liquidate all or a portion of a Participant's Financial Security at its discretion to satisfy Total Net Obligations to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

PJMSettlement may hold a defaulting Participant's Financial Security for as long as such party's positions exist and consistent with the PJM credit policy in this Attachment Q, in order to protect PJM's membership from default.

No payments shall be due to a Participant, nor shall any payments be made to a Participant, while the Participant is in default or has been declared in Breach of this policy or the Agreements, or while a Collateral Call is outstanding. PJMSettlement may apply towards an ongoing default any amounts that are held or later become available or due to the defaulting Participant through PJM's markets and systems.

In order to cover Obligations, PJMSettlement may hold a Participant's Financial Security through the end of the billing period which includes the 90th day following the last day a Participant had activity, open positions, or accruing obligations (other than reconciliations and true-ups), and until such Participant has satisfactorily paid any obligations invoiced through such period. Obligations incurred or accrued through such period shall survive any withdrawal from PJM. In event of non-payment, PJMSettlement may apply such Financial Security to such Participant's Obligations, even if Participant had previously announced and effected its withdrawal from PJM.

IX. DEFINITIONS:

All capitalized terms in this Attachment Q that are not otherwise defined herein shall have the same meaning as they are defined in the Agreements.

Affiliate
Affiliate is defined in the PJM Operating Agreement, §1.2.

Agreements
Agreements are the Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, the Reliability Assurance Agreement – West, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Applicant
Applicant is an entity desiring to become a PJM Member, or to take Transmission Service that has submitted the PJMSettlement Credit Application, PJMSettlement Credit Agreement and other required submittals as set forth in this policy.

Breach
Breach is the status of a Participant that does not currently meet the requirements of this policy or other provisions of the Agreements.

Business Day
A Business Day is a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Canadian Guaranty
Canadian Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of this credit policy.

Capacity
Capacity is the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Collateral Call
Collateral Call is a notice to a Participant that additional Financial Security, or possibly early payment, is required in order to remain in, or to regain, compliance with this policy.

Corporate Guaranty
Corporate Guaranty is a legal document used by one entity to guaranty the obligations of another entity.

Credit Available for Export Transactions
Credit Available for Export Transactions is a set-aside of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions
A Market Participant’s Credit Available for Virtual Transactions is the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy.

Credit-Limited Offer
Credit-Limited Offer shall mean a Sell Offer that is submitted by a Market Seller in an RPM Auction subject to a maximum credit requirement specified by such Market Seller.

Credit Score
Credit Score is a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

Export Credit Exposure
Export Credit Exposure is determined for each Market Participant for a given Operating Day, and is the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price

The Export Nodal Reference Price at each location is the 97th percentile real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction
An Export Transaction is a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transactions Net Activity
Export Transactions Net Activity shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Export Transaction Price Factor
The Export Transaction Price Factor for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening
Export Transaction Screening is the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Financial Security
Financial Security is a cash deposit or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Foreign Guaranty
Foreign Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of this credit policy.

FTR Credit Limit
FTR Credit Limit will be equal to the amount of credit established with PJMSettlement that a Participant has specifically designated to PJMSettlement to be set aside and used for FTR

activity. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the Participant may have with PJMSettlement.

FTR Credit Requirement
FTR Credit Requirement is the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or is bidding for. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems.

FTR Flow Undiversified
FTR Flow Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Geographically Undiversified
FTR Geographically Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Historical Value
FTR Historical Value – For each FTR for each month, this is the historical weighted average value over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year. FTR Historical Values shall be calculated separately for on-peak, off-peak, and 24-hour FTRs for each month of the year. FTR Historical Values shall be adjusted by plus or minus ten percent (10%) for cleared counterflow or normal flow FTRs, respectively, in order to mitigate exposure due to uncertainty and fluctuations in actual FTR value.

FTR Monthly Credit Requirement Contribution
FTR Monthly Credit Requirement Contribution - For each FTR for each month, this is the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity
FTR Net Activity shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant
FTR Participant shall mean any Market Participant that is required to provide Financial Security in order to participate in PJM's FTR auctions.

FTR Portfolio Auction Value
FTR Portfolio Auction Value shall mean for each Participant (or Participant account), the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Market Participant
Market Participant shall have the meaning provided in the Operating Agreement.

Material
For these purposes, material is defined in §I.B.3, Material Changes. For the purposes herein, the use of the term "material" is not necessarily synonymous with use of the term by governmental agencies and regulatory bodies.

Member
Member shall have the meaning provided in the Operating Agreement.

Minimum Participation Requirements
A set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM markets, as set forth herein and in the Form of Annual Certification set forth as Appendix 1 to this Attachment Q. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Appendix 1 to this Attachment Q.

Net Obligation
Net Obligation is the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position
Net Sell Position is the amount of Net Obligation when Net Obligation is negative.

Nodal Reference Price
The Nodal Reference Price at each location is the 97th percentile price differential between hourly day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year.   In order to capture seasonality effects and maintain a two-month reference period, reference months will be grouped by two, starting with January (e.g., Jan-Feb, Mar-Apr, … , Jul-Aug, … Nov-Dec). For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

Obligation
Obligation is all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for Capacity purchases within the PJM Capacity markets will be

added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Operating Agreement of PJM Interconnection, L.L.C., ("Operating Agreement")
The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of June 2, 1997, on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Participant
A Participant is a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer.

Peak Market Activity
Peak Market Activity is a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of section II.D of this Credit Policy.

PJM Markets
The PJM Markets are the PJM Interchange Energy Market and the PJM Capacity markets as established by the Operating Agreement. Also any other markets that exist or may be established in the future wherein Participants may incur Obligations to PJMSettlement.

PJM Open Access Transmission Tariff ("O.A.T.T.")
The Open Access Transmission Tariff of PJM Interconnection, L.L.C., on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Reliability Assurance Agreement ("R.A.A.")
See the definition of the Reliability Assurance Agreement ("R.A.A.") in the Operating Agreement.

RPM Seller Credit
RPM Seller Credit is an additional form of Unsecured Credit defined in section IV of this document.

Seller Credit
A Seller Credit is a form of Unsecured Credit extended to Participants that have a consistent long-term history of selling into PJM Markets, as defined in this document.

Tangible Net Worth
Tangible Net Worth is all assets (not including any intangible assets such as goodwill) less all liabilities. Any such calculation may be reduced by PJMSettlement upon review of the available financial information.

Total Net Obligation

Total Net Obligation is all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position

Total Net Sell Position is all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Transmission Customer

Transmission Customer is a Transmission Customer is an entity taking service under Part II or Part III of the O.A.T.T.

Transmission Service

Transmission Service is any or all of the transmission services provided by PJM pursuant to Part II or Part III of the O.A.T.T.

Uncleared Bid Exposure

Uncleared Bid Exposure is a measure of exposure from Increment Offers and Decrement Bids activity relative to a Participant's established credit as defined in this policy. It is used only as a pre-screen to determine whether a Participant's Increment Offers and Decrement Bids should be subject to Increment Offer and Decrement Bid Screening.

Unsecured Credit

Unsecured Credit is any credit granted by PJMSettlement to a Participant that is not secured by a form of Financial Security.

Unsecured Credit Allowance

Unsecured Credit Allowance is Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Financial Security. See also: "Working Credit Limit."

Up-to Congestion Counterflow Transaction

An Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month

An Up-to Congestion Historical Month is a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction

An Up-to Congestion Transaction will be deemed an Up-to Congestion Prevailing Flow Transaction if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price
The Up-to Congestion Reference Price for an Up-to Congestion Transaction is the specified percentile price differential between source and sink (defined as sink price minus source price) for hourly real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30th percentile
For Up-to Congestion Counterflow Transactions when bid: 20th percentile
For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Virtual Credit Exposure
Virtual Credit Exposure is the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in this policy.

Virtual Transaction Screening
Virtual Transaction Screening is the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity
Virtual Transactions Net Activity shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Virtual Transactions Net Activity may be positive or negative.

Working Credit Limit
Working Credit Limit amount is 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement. The Working Credit Limit establishes the maximum amount of Total Net Obligation that a Market Participant may have outstanding at any time. The calculation of Working Credit Limit shall take into account applicable reductions for Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Working Credit Limit for Virtual Transactions
The Working Credit Limit for Virtual Transactions shall be calculated as 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement when the Market Participant is at or below its Peak Market Activity credit requirements as specified in section II.D of this Credit Policy. When the Market Participant provides additional Unsecured Credit Allowance and/or Financial Security in excess of its Peak Market Activity credit requirements, such additional Unsecured Credit Allowance and/or Financial Security shall not be discounted by 25% when calculating the Working Credit Limit for Virtual Transactions. The Working Credit Limit for Virtual Transactions is a component in the calculation of Credit Available for Virtual Transactions. The calculation of Working Credit Limit for Virtual Transactions shall take into account applicable reductions for

Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Appendix 1 to Attachment Q

PJM MINIMUM PARTICIPATION CRITERIA
OFFICER CERTIFICATION FORM

Participant Name: ____ ("Participant")

I, ____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. and PJM Settlement, Inc. (”PJMSettlement”) are relying on this certification as evidence that Participant meets the minimum requirements set forth in Attachment Q to the PJM Open Access Transmission Tariff ("PJM Tariff"), hereby certify that I have full authority to represent on behalf of Participant and further represent as follows, as evidenced by my initialing each representation in the space provided below:

1. All employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Amended and Restated Operating Agreement (“PJM Operating Agreement”) on behalf of the Participant have received appropriate[1] training and are authorized to transact on behalf of Participant.__________

2. Participant has written risk management policies, procedures, and controls, approved by Participant’s independent risk management function[2] and applicable to transactions in the PJM markets in which it participates and for which employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Operating Agreement have been trained, that provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Participant is exposed, including, but not limited to credit risks, liquidity risks and market risks.__________

3. An FTR Participant (as defined in Attachment Q to the PJM Tariff) must make either the following 3.a. or 3.b. additional representations, evidenced by the undersigned officer initialing either the one 3.a. representation or the six 3.b. representations in the spaces provided below:

   3.a. Participant transacts in PJM’s FTR markets with the sole intent to hedge congestion risk in connection with either obligations Participant has to serve load or rights Participant has to generate electricity in the PJM Region (“physical

[1] As used in this representation, the term “appropriate” as used with respect to training means training that is (i) comparable to generally accepted practices in the energy trading industry, and (ii) commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the participant.
[2] As used in this representation, a Participant’s “independent risk management function” can include appropriate corporate persons or bodies that are independent of the Participant’s trading functions, such as a risk management committee, a risk officer, a Participant’s board or board committee, or a board or committee of the Participant’s parent company.

transactions") and monitors all of the Participant's FTR market activity to endeavor to ensure that its FTR positions, considering both the size and pathways of the positions, are either generally proportionate to or generally do not exceed the Participant's physical transactions, and remain generally consistent with the Participant's intention to hedge its physical transactions.__________

3.b. On no less than a weekly basis, Participant values its FTR positions and engages in a probabilistic assessment of the hypothetical risk of such positions using analytically based methodologies, predicated on the use of industry accepted valuation methodologies.__________

Such valuation and risk assessment functions are performed either by persons within Participant's organization independent from those trading in PJM's FTR markets or by an outside firm qualified and with expertise in this area of risk management.__________

Having valued its FTR positions and quantified their hypothetical risks, Participant applies its written policies, procedures and controls to limit its risks using industry recognized practices, such as value-at-risk limitations, concentration limits, or other controls designed to prevent Participant from purposefully or unintentionally taking on risk that is not commensurate or proportional to Participant's financial capability to manage such risk.__________

Exceptions to Participant's written risk policies, procedures and controls applicable to Participant's FTR positions are documented and explain a reasoned basis for the granting of any exception.__________

Participant has provided to PJMSettlement, in accordance with Section I A. of Attachment Q to the PJM Tariff, a copy of its current governing risk management policies, procedures and controls applicable to its FTR trading activities.__________

If the risk management policies, procedures and controls applicable to Participant's FTR trading activities submitted to PJMSettlement were submitted prior to the current certification, Particpant certifies that no substantive changes have been made to such policies, procedures and controls applicable to its FTR trading activities since such submission.__________

4. Participant has appropriate personnel resources, operating procedures and technical abilities to promptly and effectively respond to all PJM communications and directions.__________

5. Participant has demonstrated compliance with the Minimum Capitalization criteria set forth in Attachment Q of the PJM Open Access Transmission Tariff that are applicable to the PJM market(s) in which Participant transacts, and is not aware of any change having occurred or being imminent that would invalidate such compliance.__________

6. All Participants must certify and initial in at least one of the four sections below:

   a. I certify that Participant qualifies as an "appropriate person" as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act or an "eligible contract participant" as that term is defined under Section 1a(18), or successor provision, of the Commodity Exchange Act. I certify that Participant will cease transacting in PJM's Markets and notify PJMSettlement immediately if Participant no longer qualifies as an "appropriate person" or "eligible contract participant."__________

      If providing financial statements to support Participant's certification of qualification as an "appropriate person:"

      I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $5 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

      If providing financial statements to support Participant's certification of qualification as an "eligible contract participant:"

      I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $10 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

   b. I certify that Participant has provided an unlimited Corporate Guaranty in a form acceptable to PJM as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant per Participant for which the issuer has issued an unlimited Corporate Guaranty. I certify that Participant will cease transacting PJM's Markets and notify PJMSettlement immediately if issuer of the unlimited Corporate Guaranty for Participant no longer has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty.__________

I certify that the issuer of the unlimited Corporate Guaranty to Participant continues to have at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty. I acknowledge that PJM and PJMSettlement are relying upon my certifications to maintain compliance with federal regulatory requirements.__________

c. I certify that Participant fulfills the eligibility requirements of the Commodity Futures Trading Commission exemption order (78 F.R. 19880 – April 2, 2013) by being in the business of at least one of the following in the PJM Region as indicated below (initial those applicable):

1. Generating electric energy, including Participants that resell physical energy acquired from an entity generating electric energy:__________

2. Transmitting electric energy:__________

3. Distributing electric energy delivered under Point-to-Point or Network Integration Transmission Service, including scheduled import, export and wheel through transactions:__________

4. Other electric energy services that are necessary to support the reliable operation of the transmission system:__________

Description only if c(4) is initialed:

____

Further, I certify that Participant will cease transacting in PJM's Markets and notify PJMSettlement immediately if Participant no longer performs at least one of the functions noted above in the PJM Region. I acknowledge that PJM and PJMSettlement are relying on my certification to maintain compliance with federal energy regulatory requirements.__________

d. I certify that Participant has provided a letter of credit of $5 million or more to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Participant acknowledges cannot be utilized to meet its credit requirements to PJMSettlement. I acknowledge that PJM and PJMSettlement are relying on the provision of this letter of credit and my certification to maintain compliance with federal regulatory requirements.__________

7. I acknowledge that I have read and understood the provisions of Attachment Q of the PJM Tariff applicable to Participant's business in the PJM markets, including those provisions describing PJM's minimum participation requirements and the enforcement actions available to PJMSettlement of a Participant not satisfying those requirements. I acknowledge that the information provided herein is true and accurate to the best of my belief and knowledge after due investigation. In addition, by signing this Certification, I

acknowledge the potential consequences of making incomplete or false statements in this Certification.___________

Date: ______________________________ ______________________________________

(Signature)

Print Name: ______________________________________

Title: ______________________________________

ATTACHMENT Q

PJM CREDIT POLICY

POLICY STATEMENT:

It is the policy of PJM Interconnection, LLC ("PJM") that prior to an entity participating in the PJM Markets, or in order to take Transmission Service, the entity must demonstrate its ability to meet PJMSettlement's credit requirements.

Prior to becoming a Market Participant, Transmission Customer, and/or Member of PJM, PJMSettlement must accept and approve a Credit Application (including Credit Agreement) from such entity and establish a Working Credit Limit with PJMSettlement. PJMSettlement shall approve or deny an accepted Credit Application on the basis of a complete credit evaluation including, but not be limited to, a review of financial statements, rating agency reports, and other pertinent indicators of credit strength.

POLICY INTENT:

This credit policy describes requirements for: (1) the establishment and maintenance of credit by Market Participants, Transmission Customers, and entities seeking either such status (collectively "Participants"), pursuant to one or more of the Agreements, and (2) forms of security that will be deemed acceptable (hereinafter the "Financial Security") in the event that the Participant does not satisfy the financial or other requirements to establish Unsecured Credit.

This policy also sets forth the credit limitations that will be imposed on Participants in order to minimize the possibility of failure of payment for services rendered pursuant to the Agreements, and conditions that will be considered an event of default pursuant to this policy and the Agreements.

These credit rules may establish certain set-asides of credit for designated purposes (such as for FTR or RPM activity). Such set-asides shall be construed to be applicable to calculation of credit requirements only, and shall not restrict PJMSettlement's ability to apply such designated credit to any obligation(s) in case of a default.

PJMSettlement may post on PJM's web site, and may reference on OASIS, a supplementary document which contains additional business practices (such as algorithms for credit scoring) that are not included in this document. Changes to the supplementary document will be subject to stakeholder review and comment prior to implementation. PJMSettlement may specify a required compliance date, not less than 15 days from notification, by which time all Participants must comply with provisions that have been revised in the supplementary document.

APPLICABILITY:

This policy applies to all Participants.

IMPLEMENTATION:

I. CREDIT EVALUATION

Each Participant will be subject to a complete credit evaluation in order for PJMSettlement to determine creditworthiness and to establish an **Unsecured Credit Allowance**, if applicable; provided, however, that a Participant need not provide the information specified in section I.A or I.B if it notifies PJMSettlement in writing that it does not seek any Unsecured Credit Allowance. PJMSettlement will identify any necessary Financial Security requirements and establish a Working Credit Limit for each Participant. In addition, PJMSettlement will perform follow-up credit evaluations on at least an annual basis.

If a **Corporate Guaranty** is being utilized to establish credit for a Participant, the guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

PJMSettlement will provide a Participant, upon request, with a written explanation for any change in credit levels or collateral requirements. PJMSettlement will provide such explanation within ten Business Days.

If a Participant believes that either its level of unsecured credit or its collateral requirement has been incorrectly determined, according to this credit policy, then the Participant may send a request for reconsideration in writing to PJMSettlement. Such a request should include:

- A citation to the applicable section(s) of the PJMSettlement credit policy along with an explanation of how the respective provisions of the credit policy were not carried out in the determination as made

- A calculation of what the Participant believes should be the correct credit level or collateral requirement, according to terms of the credit policy

PJMSettlement will reconsider the determination and will provide a written response as promptly as practical, but no longer than ten Business Days of receipt of the request. If the Participant still feels that the determination is incorrect, then the Participant may contest that determination. Such contest should be in written form, addressed to PJMSettlement, and should contain:

♦ A complete copy of the Participant's earlier request for reconsideration, including citations and calculations

♦ A copy of PJMSettlement's written response to its request for reconsideration

♦ An explanation of why it believes that the determination still does not comply with the credit policy

PJMSettlement will investigate and will respond to the Participant with a final determination on the matter as promptly as practical, but no longer than 20 Business Days.

Neither requesting reconsideration nor contesting the determination following such request shall relieve or delay Participant's responsibility to comply with all provisions of this credit policy.

A. Initial Credit Evaluation

In completing the initial credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor’s, Moody’s Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit with its application audited financial statements for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the Participant, if shorter. All financial and related information considered for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement.

The information should include, but not be limited to, the following:

a. If publicly traded:
   i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
   ii. Form 8-K reports disclosing Material changes, if any.

b. If privately held:
   i. Management’s Discussion & Analysis
   ii. Report of Independent Accountants
   iii. Financial Statements, including:
      - Balance Sheet
      - Income Statement
      - Statement of Cash Flows
      - Statement of Stockholder’s Equity
   iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) References

PJMSettlement may request Participants to provide with their applications at least one (1) bank and three (3) utility credit references. In the case where a Participant does not have the required utility references, trade payable vendor references may be substituted.

4) Litigation, Commitments and Contingencies

Each Participant is also required to provide with its application information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJMSettlement or are applying for membership with PJMSettlement. Each Participant is also required to disclose the existence of any ongoing investigations by the Securities and Exchange Commission ("SEC"), Federal Energy Regulatory Commission ("FERC"), Commodity Futures Trading Commission ("CFTC"), or any other governing, regulatory, or standards body. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

B. Ongoing Credit Evaluation

On at least an annual basis, PJMSettlement will perform follow-up credit evaluations on all Participants. In completing the credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit audited annual financial statements as soon as they become available and no later than 120 days after fiscal year end. Each Participant is also required to provide PJMSettlement with quarterly financial statements promptly upon their issuance, but no later than 60 days after the end of each quarter. All financial and related information considered

for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement. If financial statements are not provided within the timeframe required, the Participant may not be granted an Unsecured Credit Allowance.

The information should include, but not be limited to, the following:

a. If publicly traded:
   i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
   ii. Form 8-K reports disclosing Material changes, if any, immediately upon issuance.

b. If privately held:
   i. Management's Discussion & Analysis
   ii. Report of Independent Accountants
   iii. Financial Statements, including:
      - Balance Sheet
      - Income Statement
      - Statement of Cash Flows
      - Statement of Stockholder's Equity
   iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) Material Changes

Each Participant is responsible for informing PJMSettlement immediately, in writing, of any Material change in its financial condition. However, PJMSettlement may also independently establish from available information that a Participant has experienced a Material change in its financial condition without regard to whether such Participant has informed PJMSettlement of the same.

For the purpose of this policy, a Material change in financial condition may include, but not be limited to, any of the following:

a. a downgrade of any debt rating by any rating agency;
b. being placed on a credit watch with negative implications by any rating agency;
c. a bankruptcy filing;
d. insolvency;

e. a report of a quarterly or annual loss or a decline in earnings of ten percent or more compared to the prior period;
f. restatement of prior financial statements;
g. the resignation of key officer(s);
h. the filing of a lawsuit that could adversely impact any current or future financial results by ten percent or more;
i. financial default in another organized wholesale electric market futures exchange or clearing house;
j. revocation of a license or other authority by any Federal or State regulatory agency; where such license or authority is necessary or important to the Participants continued business for example, FERC market-based rate authority, or State license to serve retail load; or
k. a significant change in credit default spreads, market capitalization, or other market-based risk measurement criteria, such as a recent increase in Moody's KMV Expected Default Frequency (EDF^{tm}) that is noticeably greater than the increase in its peers' EDF^{tm} rates, or a collateral default swap (CDS) premium normally associated with an entity rated lower than investment grade.

If PJMSettlement determines that a Material change in the financial condition of the Participant has occurred, it may require the Participant to provide Financial Security within two Business Days, in an amount and form approved by PJMSettlement. If the Participant fails to provide the required Financial Security, the Participant shall be in default under this credit policy.

In the event that PJMSettlement determines that a Material change in the financial condition of a Participant warrants a requirement to provide Financial Security, PJMSettlement shall provide the Participant with a written explanation of why such determination was made. However, under no circumstances shall the requirement that a Participant provide the requisite Financial Security be deferred pending the issuance of such written explanation.

4) Litigation, Commitments, and Contingencies

Each Participant is also required to provide information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon initiation or change or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJM or are applying for membership within PJM. Each Participant is also required to disclose the existence of any ongoing investigations by the SEC, FERC, CFTC or any other governing, regulatory, or standards body. These disclosures shall be made upon initiation or change, or as requested by PJMSettlement.

C. Corporate Guaranty

If a Corporate Guaranty is being utilized to establish credit for a Participant, the Guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

An irrevocable and unconditional Corporate Guaranty may be utilized as part of the credit evaluation process, but will not be considered a form of Financial Security. The Corporate Guaranty will be considered a transfer of credit from the Guarantor to the Participant. The Corporate Guaranty must guarantee the (i) full and prompt payment of all amounts payable by the Participant under the Agreements, and (ii) performance by the Participant under this policy.

The Corporate Guaranty should clearly state the identities of the "Guarantor," "Beneficiary" (PJMSettlement) and "Obligor" (Participant). The Corporate Guaranty must be signed by an officer of the Guarantor, and must demonstrate that it is duly authorized in a manner acceptable to PJMSettlement. Such demonstration may include either a Corporate Seal on the Guaranty itself, or an accompanying executed and sealed Secretary's Certificate noting that the Guarantor was duly authorized to provide such Corporate Guaranty and that the person signing the Corporate Guaranty is duly authorized, or other manner acceptable to PJMSettlement.

A Participant supplying a Corporate Guaranty must provide the same information regarding the Guarantor as is required in the "Initial Credit Evaluation" §I.A. and the "Ongoing Evaluation" §I.B. of this policy, including providing the Rating Agency Reports, Financial Statements and Related Information, References, Litigation Commitments and Contingencies, and Other Disclosures. A Participant supplying a Foreign or Canadian Guaranty must also satisfy the requirements of §I.C.1 or §I.C.2, as appropriate.

If there is a Material change in the financial condition of the Guarantor or if the Corporate Guaranty comes within 30 days of expiring without renewal, the Participant will be required to provide Financial Security either in the form of a cash deposit or a letter of credit. Failure to provide the required Financial Security within two Business Days after request by PJMSettlement will constitute an event of default under this credit policy. A Participant may request PJMSettlement to perform a credit evaluation in order to determine creditworthiness and to establish an Unsecured Credit Allowance, if applicable. If PJMSettlement determines that a Participant does qualify for a sufficient Unsecured Credit Allowance, then Financial Security will not be required.

The PJMSettlement Credit Application contains an acceptable form of Corporate Guaranty that should be utilized by a Participant choosing to establish its credit with a Corporate Guaranty. If the Corporate Guaranty varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a Corporate Guaranty and meeting the policy provisions are the responsibility of the Participant.

1) Foreign Guaranties

A Foreign Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in a country other than the United States or Canada. The entity providing a Foreign Guaranty on behalf of a Participant is a Foreign Guarantor. A Participant may provide a Foreign

Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met:

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Foreign Guaranty at any time, including for material adverse circumstances or occurrences.

a. A Foreign Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.
   iv. Will not be accepted towards a Participant's Unsecured Credit Allowance for more than the following limits, depending on the Foreign Guarantor's credit rating:

Rating of Foreign Guarantor	Maximum Accepted Guaranty if Country Rating is AAA	Maximum Accepted Guaranty if Country Rating is AA+
A- and above	USD50,000,000	USD30,000,000
BBB+	USD30,000,000	USD20,000,000
BBB	USD10,000,000	USD10,000,000
BBB- or below	USD 0	USD 0

   v. May not exceed 50% of the Participant's total credit, if the Foreign Grantor is rated less than BBB+.

b. A Foreign Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Foreign Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must have a Senior Unsecured (or equivalent, in PJMSettlement's sole discretion) rating of BBB (one notch above BBB-) or greater by any and all agencies that provide rating coverage of the entity.
   vi. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance

vii. Must provide a Secretary’s Certificate certifying the adoption of Corporate Resolutions:
    1. Authorizing and approving the Guaranty; and
    2. Authorizing the Officers to execute and deliver the Guaranty on behalf of the Guarantor.

viii. Must be domiciled in a country with a minimum long-term sovereign (or equivalent) rating of AA+/Aa1, with the following conditions:
    1. Sovereign ratings must be available from at least two rating agencies acceptable to PJMSettlement (e.g. S&P, Moody’s, Fitch, DBRS).
    2. Each agency’s sovereign rating for the domicile will be considered to be the lowest of: country ceiling, senior unsecured government debt, long-term foreign currency sovereign rating, long-term local currency sovereign rating, or other equivalent measures, at PJMSettlement’s sole discretion.
    3. Whether ratings are available from two or three agencies, the lowest of the two or three will be used.

ix. Must be domiciled in a country that recognizes and enforces judgments of US courts.

x. Must demonstrate financial commitment to activity in the United States as evidenced by one of the following:
    1. American Depository Receipts (ADR) are traded on the New York Stock Exchange, American Stock Exchange, or NASDAQ.
    2. Equity ownership worth over USD100,000,000 in the wholly-owned or majority owned subsidiaries in the United States.

xi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this credit policy.

xii. Must pay for all expenses incurred by PJMSettlement related to reviewing and accepting a foreign guaranty beyond nominal in-house credit and legal review.

xiii. Must, at its own cost, provide PJMSettlement with independent legal opinion from an attorney/solicitor of PJMSettlement’s choosing and licensed to practice law in the United States and/or Guarantor’s domicile, in form and substance acceptable to PJMSettlement in its sole discretion, confirming the enforceability of the Foreign Guaranty, the Guarantor’s legal authorization to grant the Guaranty, the conformance of the Guaranty, Guarantor, and Guarantor's domicile to all of these requirements, and such other matters as PJMSettlement may require in its sole discretion.

2) Canadian Guaranties

A Canadian Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in Canada and satisfies all of the provisions below. The entity providing a Canadian Guaranty on behalf of a Participant is a Canadian Guarantor. A Participant may provide a Canadian Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met.

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Canadian Guaranty at any time for reasonable cause, including adverse material circumstances.

a. A Canadian Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.

b. A Canadian Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Canadian Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance.

   vi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Credit Policy.

Ia. MINIMUM PARTICIPATION REQUIREMENTS

A. PJM Market Participation Eligibility Requirements

To be eligible to transact in PJM Markets, a Market Participant must demonstrate in accordance with the Risk Management and Verification processes set forth below that it qualifies in one of the following ways:

1. an "appropriate person," as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act, or;

2. an "eligible contract participant," as that term is defined in Section 1a(18), or successor provision, of the Commodity Exchange Act, or;

3. a business entity or person who is in the business of: (1) generating, transmitting, or distributing electric energy, or (2) providing electric energy services that are necessary to support the reliable operation of the transmission system, or;

4. a Market Participant seeking eligibility as an "appropriate person" providing an unlimited Corporate Guaranty in a form acceptable to PJMSettlement as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty, or;

5. a Market Participant providing a letter of credit of at least $5 million to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJMSettlement.

If, at any time, a Market Participant cannot meet the eligibility requirements set forth above, it shall immediately notify PJMSettlement and immediately cease conducting transactions in the PJM Markets. PJMSettlement shall terminate a Market Participant's transaction rights in the PJM Markets if, at any time, it becomes aware that the Market Participant does not meet the minimum eligibility requirements set forth above.

In the event that a Market Participant is no longer able to demonstrate it meets the minimum eligibility requirements set forth above, and possesses, obtains or has rights to possess or obtain, any open or forward positions in PJM's Markets, PJMSettlement may take any such action it deems necessary with respect to such open or forward positions, including, but not limited to, liquidation, transfer, assignment or sale; provided, however, that the Market Participant will, notwithstanding its ineligibility to participate in the PJM Markets, be entitled to any positive market value of those positions, net of any obligations due and owing to PJM and/or PJMSettlement.

B. Risk Management and Verification

All Participants shall provide to PJMSettlement an executed copy of the annual certification set forth in Appendix 1 to this Attachment Q. This certification shall be provided before an entity is eligible to participate in the PJM Markets and shall be initially submitted to PJMSettlement together with the entity's Credit Application. Thereafter, it shall be submitted each calendar year by all Participants during a period beginning on January 1 and ending April 30, except that new Participants who became eligible to participate in PJM markets during the period of January through April shall not be required to resubmit such certification until the following calendar year. Except for certain FTR Participants (discussed below) or in cases of manifest error, PJMSettlement will accept such certifications as a matter of course and Participants will not need further notice from PJMSettlement before commencing or maintaining their eligibility to participate in PJM markets. A Participant that fails to provide its annual certification by April 30 shall be ineligible to transact in the PJM markets and PJM will disable the Participant's access to the PJM markets until such time as PJMSettlement receives the Participant's certification.

Participants acknowledge and understand that the annual certification constitutes a representation upon which PJMSettlement will rely. Such representation is additionally made under the PJM Tariff, filed with and accepted by FERC, and any inaccurate or incomplete statement may subject the Participant to action by FERC. Failure to comply with any of the criteria or

requirements listed herein or in the certification may result in suspension of a Participant's transaction rights in the PJM markets.

Certain FTR Participants (those providing representations found in paragraph 3.b of the annual certification set forth in Appendix 1 to this Attachment Q) are additionally required to submit to PJMSettlement (at the time they make their annual certification) a copy of their current governing risk control policies, procedures and controls applicable to their FTR trading activities, except that if no substantive changes have been made to such policies, practices and/or controls applicable to their FTR trading activities, they may instead submit to PJMSettlement a certification stating that no changes have been made. PJMSettlement will review such documentation to verify that it appears generally to conform to prudent risk management practices for entities trading in FTR-type markets. If principles or best practices relating to risk management in FTR-type markets are published, as may be modified from time to time, by a third-party industry association, such as the Committee of Chief Risk Officers, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the fundamental sufficiency of the FTR Participant's risk controls. Those FTR Participants subject to this provision shall make a one-time payment of $1,000.00 to PJMSettlement to cover costs associated with review and verification. Thereafter, if such FTR Participant's risk policies, procedures and controls applicable to its FTR trading activities change substantively, it shall submit such modified documentation, without charge, to PJMSettlement for review and verification at the time it makes its annual certification. Such FTR Participant's continued eligibility to participate in the PJM FTR markets is conditioned on PJMSettlement notifying such FTR Participant that its annual certification, including the submission of its risk policies, procedures and controls, has been accepted by PJMSettlement. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph, however, in all circumstances, PJMSettlement and any third-party it may retain will treat as confidential the documentation provided by an FTR Participant under this paragraph, consistent with the applicable provisions of PJM's Operating Agreement.

An FTR Participant that makes the representation in paragraph 3.a of the annual certification understand that PJMSettlement, given the visibility it has over a Participant's overall market activity in performing billing and settlement functions, may at any time request the FTR Participant provide additional information demonstrating that it is in fact eligible to make the representation in paragraph 3.a of the annual certification. If such additional information is not provided or does not, in PJMSettlement's judgment, demonstrate eligibility to make the representation in paragraph 3.a of the annual certification, PJMSettlement will require the FTR Participant to instead make the representations required in paragraph 3.b of the annual certification, including representing that it has submitted a copy of its current governing risk control policies, procedures and controls applicable to its FTR trading activities. If the FTR Participant cannot or does not make those representations as required in paragraph 3.b of the annual certification, then PJM will terminate the FTR Participant's rights to purchase FTRs in the FTR market and may terminate the FTR Participant's rights to sell FTRs in the PJM FTR market.

PJMSettlement shall also conduct a periodic compliance verification process to review and verify, as applicable, Participants' risk management policies, practices, and procedures pertaining to the Participants' activities in the PJM markets. Such review shall include verification that:

1. The risk management framework is documented in a risk policy addressing market, credit and liquidity risks.
2. The Participant maintains an organizational structure with clearly defined roles and responsibilities that clearly segregates trading and risk management functions.
3. There is clarity of authority specifying the types of transactions into which traders are allowed to enter.
4. The Participant has requirements that traders have adequate training relative to their authority in the systems and PJM markets in which they transact.
5. As appropriate, risk limits are in place to control risk exposures.
6. Reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization.
7. Processes are in place for qualified independent review of trading activities.
8. As appropriate, there is periodic valuation or mark-to-market of risk positions.

If principles or best practices relating to risk management in PJM-type markets are published, as may be modified from time to time, by a third-party industry association, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the sufficiency of the Participant's risk controls. PJMSettlement may select Participants for review on a random basis and/or based on identified risk factors such as, but not limited to, the PJM markets in which the Participant is transacting, the magnitude of the Participant's transactions in the PJM markets, or the volume of the Participant's open positions in the PJM markets. Those Participants notified by PJMSettlement that they have been selected for review shall, upon 14 calendar days notice, provide a copy of their current governing risk control policies, procedures and controls applicable to their PJM market activities and shall also provide such further information or documentation pertaining to the Participants' activities in the PJM markets as PJMSettlement may reasonably request. Participants selected for risk management verification through a random process and satisfactorily verified by PJMSettlement shall be excluded from such verification process based on a random selection for the subsequent two years. PJMSettlement shall annually randomly select for review no more than 20% of the Participants in each member sector.

Each selected Participant's continued eligibility to participate in the PJM markets is conditioned upon PJMSettlement notifying the Participant of successful completion of PJMSettlement's verification of the Participant's risk management policies, practices and procedures, as discussed

herein. However, if PJMSettlement notifies the Participant in writing that it could not successfully complete the verification process, PJMSettlement shall allow such Participant 14 calendar days to provide sufficient evidence for verification prior to declaring the Participant as ineligible to continue to participate in PJM's markets, which declaration shall be in writing with an explanation of why PJMSettlement could not complete the verification. If, prior to the expiration of such 14 calendar days, the Participant demonstrates to PJMSettlement that it has filed with the Federal Energy Regulatory Commission an appeal of PJMSettlement’s risk management verification determination, then the Participant shall retain its transaction rights, pending the Commission’s determination on the Participant’s appeal. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph. PJMSettlement and any third party it may retain will treat as confidential the documentation provided by a Participant under this paragraph, consistent with the applicable provisions of the Operating Agreement. If PJMSettlement retains such outside expertise, a Participant may direct in writing that PJMSettlement perform the risk management review and verification for such Participant instead of utilizing a third party, provided however, that employees and contract employees of PJMSettlement and PJM shall not be considered to be such outside expertise or third parties.

Participants are solely responsible for the positions they take and the obligations they assume in PJM markets. PJMSettlement hereby disclaims any and all responsibility to any Participant or PJM Member associated with Participant’s submitting or failure to submit its annual certification or PJMSettlement’s review and verification of an FTR Participant’s risk policies, procedures and controls. Such review and verification is limited to demonstrating basic compliance by an FTR Participant with the representation it makes under paragraph 3.b of its annual certification showing the existence of written policies, procedures and controls to limit its risk in PJM’s FTR markets and does not constitute an endorsement of the efficacy of such policies, procedures or controls.

C. Capitalization

In addition to the Annual Certification requirements in Appendix 1 to this Attachment Q, a Participant must demonstrate that it meets the minimum financial requirements appropriate for the PJM market(s) in which it transacts by satisfying either the Minimum Capitalization or the Provision of Collateral requirements listed below:

1. Minimum Capitalization

FTR Participants must demonstrate a tangible net worth in excess of $1 million or tangible assets in excess of $10 million. Other Participants must demonstrate a tangible net worth in excess of $500,000 or tangible assets in excess of $5 million.

a. In either case, consideration of “tangible” assets and net worth shall exclude assets (net of any matching liabilities, assuming the result is a positive value) which PJMSettlement reasonably believes to be restricted, highly risky, or potentially unavailable to settle a claim in the event of default. Examples include, but are not

limited to, restricted assets and Affiliate assets, derivative assets, goodwill, and other intangible assets.

b. Demonstration of "tangible" assets and net worth may be satisfied through presentation of an acceptable Corporate Guaranty, provided that both:

(i) the guarantor is an affiliate company that satisfies the tangible net worth or tangible assets requirements herein, and;

(ii) the Corporate Guaranty is either unlimited or at least $500,000.

If the Corporate Guaranty presented by the Participant to satisfy these Capitalization requirements is limited in value, then the Participant's resulting Unsecured Credit Allowance shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this Credit Policy, or:

(2) the face value of the Corporate Guaranty, reduced by $500,000 and further reduced by 10%. (For example, a $10.5 million Corporate Guaranty would be reduced first by $500,000 to $10 million and then further reduced 10% more to $9 million. The resulting $9 million would be the Participant's Unsecured Credit Allowance available through the Corporate Guaranty).

In the event that a Participant provides collateral in addition to a limited Corporate Guaranty to increase its available credit, the value of such collateral shall be reduced by 10%. This reduced value shall be deemed Financial Security and available to satisfy the requirements of this Credit Policy.

Demonstrations of capitalization must be presented in the form of audited financial statements for the Participant's most recent fiscal year.

2. Provision of Collateral

If a Participant does not demonstrate compliance with its applicable Minimum Capitalization Requirements above, it may still qualify to participate in PJM's markets by posting additional collateral, subject to the terms and conditions set forth herein.

Any collateral provided by a Participant unable to satisfy the Minimum Capitalization Requirements above will be restricted in the following manner:

i. Collateral provided by FTR Participants shall be reduced by $500,000 and then further reduced by 10%. This reduced amount shall be considered the Financial Security provided by the Participant and available to satisfy requirements of this Credit Policy.

ii. Collateral provided by other Participants that engage in Virtual Transactions or Export Transactions shall be reduced by $200,000 and then further reduced by 10%. This reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

iii. Collateral provided by other Participants that do not engage in Virtual Transactions or Export Transactions shall be reduced by 10%, and this reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

In the event a Participant that satisfies the Minimum Participation Requirements through provision of collateral also provides a Corporate Guaranty to increase its available credit, then the Participant's resulting Unsecured Credit Allowance conveyed through such Guaranty shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this credit policy, or,

(2) the face value of the Guaranty, reduced by 10%.

II. CREDIT ALLOWANCE AND WORKING CREDIT LIMIT

PJMSettlement's credit evaluation process will include calculating a Credit Score for each Participant. The credit score will be utilized to determine a Participant's Unsecured Credit Allowance.

Participants who do not qualify for an Unsecured Credit Allowance will be required to provide Financial Security based on their Peak Market Activity, as provided below.

A corresponding Working Credit Limit will be established based on the Unsecured Credit Allowance and/or the Financial Security provided.

Where Participant of PJM are considered Affiliates, Unsecured Credit Allowances and Working Credit Limits will be established for each individual Participant, subject to an aggregate maximum amount for all Affiliates as provided for in §II.F of this policy.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

A. Credit Score

For participants with credit ratings, a Credit Score will be assigned based on their senior unsecured credit rating and credit watch status as shown in the table below. If an explicit senior unsecured rating is not available, PJMSettlement may impute an equivalent rating from other ratings that are available. For Participants without a credit rating, but who wish to be considered for unsecured Credit, a Credit Score will be generated from PJMSettlement's review and analysis of various factors that are predictors of financial strength and creditworthiness. Key factors in the scoring process include, financial ratios, and years in business. PJMSettlement will consistently apply the measures it uses in determining Credit Scores. The credit scoring methodology details are included in a supplementary document available on OASIS.

Rated Entities Credit Scores

Rating	Score	Score Modifier	
		Credit Watch Negative	Credit Watch Positive
AAA	100	-1.0	0.0
AA+	99	-1.0	0.0
AA	99	-1.0	0.0
AA-	98	-1.0	0.0
A+	97	-1.0	0.0
A	96	-2.0	0.0
A-	93	-3.0	1.0
BBB+	88	-4.0	2.0
BBB	78	-4.0	2.0
BBB-	65	-4.0	2.0
BB+ and below	0	0.0	0.0

B. Unsecured Credit Allowance

PJMSettlement will determine a Participant's Unsecured Credit Allowance based on its Credit Score and the parameters in the table below. The maximum Unsecured Credit Allowance is the lower of:

1) A percentage of the Participant's Tangible Net Worth, as stated in the table below, with the percentage based on the Participant's credit score; and

2) A dollar cap based on the credit score, as stated in the table below:

Credit Score	Tangible Net Worth Factor	Maximum Unsecured Credit Allowance ($ Million)
91-100	2.125 – 2.50%	$50
81-90	1.708 – 2.083%	$42
71-80	1.292 – 1.667%	$33
61-70	0.875 – 1.25%	$7
51-60	0.458 – 0.833%	$0-$2
50 and Under	0%	$0

If a Corporate Guaranty is utilized to establish an Unsecured Credit Allowance for a Participant, the value of a Corporate Guaranty will be the lesser of:

- The limit imposed in the Corporate Guaranty;
- The Unsecured Credit Allowance calculated for the Guarantor; and
- A portion of the Unsecured Credit Allowance calculated for the Guarantor in the case of Affiliated Participants.

PJMSettlement has the right at any time to modify any Unsecured Credit Allowance and/or require additional Financial Security as may be deemed reasonably necessary to support current market activity. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.

PJMSettlement will maintain a posting of each Participant's unsecured Credit Allowance, along with certain other credit related parameters, on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

~~C. Seller Credit~~

~~Participants that have maintained a Net Sell Position for each of the prior 12 months are eligible for Seller Credit, which is an additional form of Unsecured Credit. A Participant's Seller Credit will be equal to sixty percent of the Participant's thirteenth smallest weekly Net Sell Position invoiced in the past 52 weeks.~~

~~Each Participant receiving Seller Credit must maintain both its Seller Credit and its Total Net Sell Position equal to or greater than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided.~~

~~For Participants receiving Seller Credit, PJMSettlement may forecast the Participant's Total Net Sell Position considering the Participant's current Total Net Sell Position, recent trends in the Participant's Total Net Sell Position, and other information available to PJMSettlement, such as, but not limited to, known generator outages, changes in load responsibility, and bilateral~~

~~transactions impacting the Participant. If PJMSettlement's forecast ever indicates that the Participant's Total Net Sell Position may in the future be less than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided, then PJMSettlement may require Financial Security as needed to cover the difference. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.~~

~~Any Financial Security required by PJMSettlement pursuant to these provisions for Seller Credit will be returned once the requirement for such Financial Security has ended. Seller Credit may not be conveyed to another entity through use of a guaranty. Seller Credit shall be subject to the cap on available Unsecured Credit set forth in Section II.F.~~

C~~D~~. Peak Market Activity and Financial Security Requirement

A PJM Participant or Applicant that has an insufficient Unsecured Credit Allowance to satisfy its Peak Market Activity will be required to provide Financial Security such that its Unsecured Credit Allowance and Financial Security together are equal to its Peak Market Activity in order to secure its transactional activity in the PJM Market.

Peak Market Activity for Participants will be determined semi-annually beginning in the first complete billing week in the months of April and October. Peak Market Activity shall be the greater of the initial Peak Market Activity, as explained below, or the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two, or three week period, ending within a respective semi-annual period. However, Peak Market Activity shall not exceed the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two or three week period in the prior 52 weeks.

Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

The initial Peak Market Activity for Applicants will be determined by PJMSettlement based on a review of an estimate of their transactional activity for all PJM markets and services over the next 52 weeks, which the Applicant shall provide to PJMSettlement.

The initial Peak Market Activity for Participants, calculated at the beginning of each respective semi-annual period, shall be the three-week average of all non-zero invoice totals over the previous 52 weeks. This calculation shall be performed and applied within three business days following the day the invoice is issued for the first full billing week in the current semi-annual period.

Prepayments shall not affect Peak Market Activity unless otherwise agreed to in writing pursuant to this Credit Policy.

All Peak Market Activity calculations shall take into account reductions of invoice values effectuated by early payments which are applied to reduce a Participant's Peak Market Activity

as contemplated by other terms of the Credit Policy; provided that the initial Peak Market Activity shall not be less than the average value calculated using the weeks for which no early payment was made.

A Participant may reduce its Financial Security Requirement by agreeing in writing (in a form acceptable to PJMSettlement) to make additional payments, including prepayments, as and when necessary to ensure that such Participant's Total Net Obligation at no time exceeds such reduced Financial Security Requirement.

PJMSettlement may, at its discretion, adjust a Participant's Financial Security Requirement if PJMSettlement determines that the Peak Market Activity is not representative of such Participant's expected activity, as a consequence of known, measurable, and sustained changes. Such changes may include the loss (without replacement) of short-term load contracts, when such contracts had terms of three months or more and were acquired through state-sponsored retail load programs, but shall not include short-term buying and selling activities.

PJMSettlement may waive the Financial Security Requirement for a Participant that agrees in writing that it shall not, after the date of such agreement, incur obligations under any of the Agreements. Such entity's access to all electronic transaction systems administered by PJM shall be terminated.

PJMSettlement will maintain a posting of each Participant's Financial Security Requirement on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

D~~E~~. Working Credit Limit

PJMSettlement will establish a Working Credit Limit for each Participant against which its **Total Net Obligation** will be monitored. The Working Credit Limit is defined as 75% of the Financial Security provided to PJMSettlement and/or 75% of the Unsecured Credit Allowance determined by PJMSettlement based on a credit evaluation, as reduced by any applicable credit requirement determinants defined in this policy. A Participant's Total Net Obligation should not exceed its Working Credit Limit.

> Example: After a credit evaluation by PJMSettlement, a Participant is deemed able to support an Unsecured Credit Allowance of $10.0 million. The Participant will be assigned a Working Credit Limit of $8.5 million. PJMSettlement will monitor the Participant's Total Net Obligations against the Working Credit Limit.

A Participant with an Unsecured Credit Allowance may choose to provide Financial Security in order to increase its Working Credit Limit. A Participant with no Unsecured Credit Allowance may also choose to increase its Working Credit Limit by providing Financial Security in an amount greater than its Peak Market Activity.

If a Participant's Total Net Obligation approaches its Working Credit Limit, PJMSettlement may require the Participant to make an advance payment or increase its Financial Security in order to maintain its Total Net Obligation below its Working Credit Limit. Except as explicitly provided

below, advance payments shall not serve to reduce the Participant's Peak Market Activity for the purpose of calculating credit requirements.

> Example: After 10 days, and with 5 days remaining before the bill is due to be paid, a Participant approaches its $4.0 million Working Credit Limit. PJMSettlement may require a prepayment of $2.0 million in order that the Total Net Obligation will not exceed the Working Credit Limit.

If a Participant exceeds its Working Credit Limit or is required to make advance payments more than ten times during a 52-week period, PJMSettlement may require Financial Security in an amount as may be deemed reasonably necessary to support its Total Net Obligation.

A Participant receiving unsecured credit may make early payments up to ten times in a rolling 52-week period in order to reduce its Peak Market Activity for credit requirement purposes. Imputed Peak Market Activity reductions for credit purposes will be applied to the billing period for which the payment was received. Payments used as the basis for such reductions must be received prior to issuance or posting of the invoice for the relevant billing period. The imputed Peak Market Activity reduction attributed to any payment may not exceed the amount of Unsecured Credit for which the Participant is eligible.

E~~F~~. Credit Limit Setting For Affiliates

If two or more Participants are Affiliates and each is being granted an Unsecured Credit Allowance and a corresponding Working Credit Limit, PJMSettlement will consider the overall creditworthiness of the Affiliated Participants when determining the Unsecured Credit Allowances and Working Credit Limits in order not to grant more Unsecured Credit than the overall corporation could support.

> **Example:** Participants A and B each have a $10.0 million Corporate Guaranty from their common parent, a holding company with an Unsecured Credit Allowance calculation of $12.0 million. PJMSettlement may limit the Unsecured Credit Allowance for each Participant to $6.0 million, so the total Unsecured Credit Allowance does not exceed the corporate total of $12.0 million.

PJMSettlement will work with Affiliated Participants to allocate the total Unsecured Credit Allowance among the Affiliates while assuring that no individual Participant, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. The aggregate Unsecured Credit for a Participant, including Unsecured Credit Allowance granted based on its own creditworthiness and any Unsecured Credit Allowance conveyed through a Guaranty shall not exceed $50 million. The aggregate Unsecured Credit for a group of Affiliates shall not exceed $50 million. A group of Affiliates subject to this cap shall request PJMSettlement to allocate the maximum Unsecured Credit and Working Credit Limit amongst the group, assuring that no individual Participant or common guarantor, shall exceed the Unsecured Credit level appropriate for its credit strength and activity.

F~~G~~. Working Credit Limit Violations

1) Notification

A Participant is subject to notification when its Total Net Obligation to PJMSettlement approaches the Participant's established Working Credit Limit.

2) Suspension

A Participant that exceeds its Working Credit Limit is subject to suspension from participation in the PJM markets and from scheduling any future Transmission Service unless and until Participant's credit standing is brought within acceptable limits. A Participant will have two Business Days from notification to remedy the situation in a manner deemed acceptable by PJMSettlement. Additionally, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant's ongoing Transmission Service and participation in PJM Markets. Failure to comply with this policy will be considered an event of default under this credit policy.

G~~H~~. PJM Administrative Charges

Financial Security held by PJMSettlement shall also secure obligations to PJM for PJM administrative charges.

H~~I~~. Pre-existing Financial Security

PJMSettlement's credit requirements are applicable as of the effective date of the filing on May 5, 2010 by PJM and PJMSettlement of amendments to Attachment Q. Financial Security held by PJM prior to the effective date of such amendments shall be held by PJM for the benefit of PJMSettlement.

III. VIRTUAL TRANSACTION SCREENING

A. Credit and Financial Security

PJMSettlement does not require a Market Participant to establish separate or additional credit for submitting Virtual Transactions. If a Market Participant chooses to establish additional Financial Security and/or Unsecured Credit Allowance in order to increase its Credit Available for Virtual Transactions, the Market Participant's Working Credit Limit for Virtual Transactions shall be increased in accordance with the definition therof. The Financial Security and/or Unsecured Credit Allowance available to increase a Market Participant's Credit Available for Virtual Transactions shall be the amount of Financial Security and/or Unsecured Credit Allowance available after subtracting any credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy, as applicable.

If a Market Participant chooses to provide additional Financial Security in order to increase its **Credit Available for Virtual Transactions PJMSettlement** may establish a reasonable timeframe, not to exceed three months, for which such Financial Security must be maintained. PJMSettlement will not impose such restriction on a deposit unless a Market Participant is

notified prior to making the deposit. Such restriction, if applied, shall be applied to all future deposits by all Market Participants engaging in Virtual Transactions.

A Market Participant wishing to increase its Credit Available for Virtual Transactions by providing additional Financial Security may make the appropriate arrangements with PJMSettlement. PJMSettlement will make a good faith effort to make new Financial Security available as Credit Available for Virtual Transactions as soon as practicable after confirmation of receipt. In any event, however, Financial Security received and confirmed by noon on a business day will be applied (as provided under this policy) to Credit Available for Virtual Transactions no later than 10:00 am on the following business day. Receipt and acceptance of wired funds for cash deposit shall mean actual receipt by PJMSettlement's bank, deposit into PJMSettlement's customer deposit account, and confirmation by PJMSettlement that such wire has been received and deposited. Receipt and acceptance of letters of credit shall mean receipt of the original letter of credit or amendment thereto, and confirmation from PJMSettlement's credit and legal staffs that such letter of credit or amendment thereto conforms to PJMSettlement's requirements, which confirmation shall be made in a reasonable and practicable timeframe. To facilitate this process, bidders wiring funds for the purpose of increasing their Credit Available for Virtual Transactions are advised to specifically notify PJMSettlement that a wire is being sent for such purpose.

B. Virtual Transaction Screening Process

All Virtual Transactions submitted to PJM shall be subject to a credit screen prior to acceptance in the Day-ahead Energy Market auction. The credit screen process will automatically reject Virtual Transactions submitted by the PJM market participant if the participant's Credit Available for Virtual Transactions is exceeded by the **Virtual Credit Exposure** that is calculated based on the participant's submitted Virtual Transactions as described below.

A Participant's Virtual Credit Exposure will be calculated on a daily basis for all Virtual Transactions submitted by the market participant for the next market day using the following equation:

Virtual Credit Exposure = INC and DEC Exposure + Up-to Congestion Exposure
Where:

1) INC and DEC Exposure is calculated as:

(a) ((the total MWh bid or offered, whichever is greater, hourly at each node) x the Nodal Reference Price x 1 day) summed over all nodes and all hours; plus (b) ((the difference between the total bid MWh cleared and total offered MWh cleared hourly at each node) x Nodal Reference Price) summed over all nodes and all hours for the previous cleared Day-ahead Energy Market.

2) Up-to Congestion Exposure is calculated as:

(a) Total MWh bid hourly for each Up-to Congestion Transaction x (price bid – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours; plus (b) Total MWh cleared hourly for each Up-to Congestion Transaction x (cleared price – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours for the previous cleared Day-ahead Energy Market, provided that hours for which the calculation for an Up-to Congestion Transaction is negative, it shall be deemed to have a zero contribution to the sum.

If a Market Participant's Virtual Transactions are rejected as a result of the credit screen process, the Market Participant will be notified via an eMKT error message. A Market Participant whose Virtual Transactions are rejected may alter its Virtual Transactions so that its Virtual Credit Exposure does not exceed its Credit Available forVirtual Transactions, and may resubmit them. Virtual Transactions may be submitted in one or more groups during a day. If one or more groups of Virtual Transactions is submitted and accepted, and a subsequent group of submitted Virtual Transactions causes the total submitted Virtual Transactions to exceed the Virtual Credit Exposure, then only that subsequent set of Virtual Transactions will be rejected. Previously accepted Virtual Transactions will not be affected, though the Market Participant may choose to withdraw them voluntarily.

IV. RELIABILITY PRICING MODEL AUCTION AND PRICE RESPONSIVE DEMAND CREDIT REQUIREMENTS

Settlement during any Delivery Year of cleared positions resulting or expected to result from any Reliability Pricing Model Auction shall be included as appropriate in Peak Market Activity, and the provisions of this Attachment Q shall apply to any such activity and obligations arising therefrom. In addition, the provisions of this section shall apply to any entity seeking to participate in any RPM Auction, to address credit risks unique to such auctions. The provisions of this section also shall apply under certain circumstances to PRD Providers that seek to commit Price Responsive Demand pursuant to the provisions of the Reliability Assurance Agreement.

A. Applicability

A Market Seller seeking to submit a Sell Offer in any Reliability Pricing Model Auction based on any Capacity Resource for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before submitting such Sell Offer. A PRD Provider seeking to commit Price Responsive Demand for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before it may commit the Price Responsive Demand. Credit must be maintained until such risk of non-performance is substantially eliminated, but may be reduced commensurate with the reduction in such risk, as set forth in Section IV.C.

For purposes of this provision, a resource for which there is a materially increased risk of non-performance shall mean: (i) a Planned Generation Capacity Resource; (ii) a Planned Demand Resource or an Energy Efficiency Resource; (iii) a Qualifying Transmission Upgrade; (iv) an existing or Planned Generation Capacity Resource located outside the PJM Region that at the time it is submitted in a Sell Offer has not secured firm transmission service to the border of the

PJM Region sufficient to satisfy the deliverability requirements of the Reliability Assurance Agreement; or (v) Price Responsive Demand to the extent the responsible PRD Provider has not registered PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

B. Reliability Pricing Model Auction and Price Responsive Demand Credit Requirement

Except as provided for Credit-Limited Offers below, for any resource specified in Section IV.A, other than Price Responsive Demand, the credit requirement shall be the RPM Auction Credit Rate, as provided in Section IV.D, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction. *For Qualified Transmission Upgrades, the credit requirements shall be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit.* The RPM Auction Credit Requirement for each Market Seller shall be the sum of the credit requirements for all such resources to be offered by such Market Seller in the auction or, as applicable, cleared by such Market Seller from the relevant auctions. For Price Responsive Demand specified in section IV.A, the credit requirement shall be based on the Nominal PRD Value (stated in Unforced Capacity terms) times the Price Responsive Demand Credit Rate as set forth in section IV.E.

Except for Credit-Limited Offers, the RPM Auction Credit Requirement for a Market Seller will be reduced for any Delivery Year to the extent less than all of such Market Seller's offers clear in the Base Residual Auction or any Incremental Auction for such Delivery Year. Such reduction shall be proportional to the quantity, in megawatts, that failed to clear in such Delivery Year.

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Seller electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement, in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the Auction Credit Rate resulting from section IV.D.b.; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Seller electing this alternative, the RPM Auction Credit Requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-Limited Offer, and the RPM Auction Credit Requirement subsequent to posting of the results will be the Auction Credit Rate, as provided in Section IV.D.b, c. or d., as applicable, times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The availability and operational details of Credit-Limited Offers shall be as described in the PJM Manuals.

As set forth in Section IV.D, a Market Seller's Auction Credit Requirement shall be determined separately for each Delivery Year.

C. Reduction in Credit Requirement

As specified in Section IV.D, the RPM Auction Credit Rate may be reduced under certain circumstances after the auction has closed.

The Price Responsive Demand credit requirement shall be reduced as and to the extent the PRD Provider registers PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

In addition, the RPM Auction Credit Requirement for a Participant for any given Delivery Year shall be reduced periodically, provided the Participant successfully meets progress milestones that reduce the risk of non-performance, as follows:

a. For Planned Demand Resources and Energy Efficiency Resources, the RPM Auction Credit Requirement will be reduced in direct proportion to the megawatts of such Demand Resource that the Resource Provider qualifies as a Capacity Resource, in accordance with the procedures established under the Reliability Assurance Agreement.

b. For Existing Generation Capacity Resources located outside the PJM Region that have not secured sufficient firm transmission to the border of the PJM Region prior to the auction in which such resource is first offered, the RPM Credit Requirement shall be reduced in direct proportion to the megawatts of firm transmission service secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

c. For Planned Generation Capacity Resources, the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B beginning as of the effective date of an Interconnection Service Agreement, and shall be reduced to zero on the date of commencement of Interconnection Service.

d. For Planned Generation Capacity Resources located outside the PJM Region, the RPM Credit Requirement shall be reduced *by 50%* once the conditions in both b and c above are met, i.e., the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B when 1) the equivalent *of an* Interconnection Service Agreement *becomes effective*, and 2) 50% or more megawatts of firm transmission service have been secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement. The RPM Credit Requirement for a Planned Generation Capacity Resource located outside the PJM Region shall be reduced to zero when 1) the resource commences Interconnection Service and 2) 100% of the megawatts of firm transmission service have been secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

e. For Qualifying Transmission Upgrades, the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B beginning as of the effective date of the latest associated Interconnection Service Agreement (or, when a project will have no such agreement, an Upgrade Construction Service Agreement), and shall be reduced to zero on the date the

Qualifying Transmission Upgrade is placed in service. In addition, a Qualifying Transmission Upgrade will be allowed a reduction in its RPM Credit Requirement equal to the amount of collateral currently posted with PJM for the facility construction when the Qualifying Transmission Upgrade meets the following requirements: the Upgrade Construction Service Agreement has been fully executed, the full estimated cost to complete as most recently determined or updated by PJM has been fully paid or collateralized, and all regulatory and other required approvals (except those that must await construction completion) have been obtained. Such reduction in RPM Credit Requirement may not be transferred across different projects.

D. RPM Auction Credit Rate

As set forth in the PJM Manuals, a separate Auction Credit Rate shall be calculated for each Delivery Year prior to each Reliability Pricing Model Auction for such Delivery Year, as follows:

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (*A*) *0.3* times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (*B*) $20 per MW-day) times the number of days in such Delivery Year*; and*

(ii) For Capacity Performance Resources, the greater of ((A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year.

b. Subsequent to the posting of the results from a Base Residual Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (*A*) $20/MW-day or (*B*) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year; *and*

(ii) *For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).*

c. For any resource not previously committed for a Delivery Year that seeks to participate in an Incremental Auction, the Auction Credit Rate shall be:

*(i) For all Capacity Resources other than Capacity Performance Resources, (*the greater of (*A*) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (*B*) 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located or (*C*) $20 per MW-day) times the number of days in such Delivery Year*; and*

(ii) For Capacity Performance Resources, the (greater of (A) 0.5 times Net Cost of New Entry or (B) $20/MW-day) times the number of days in such Delivery Year.

d. Subsequent to the posting of the results of an Incremental Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) *For Base Capacity Resources:* (the greater of (*A*) $20/MW-day or (*B*) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year, but no greater than the Auction Credit Rate previously established for such resource's participation in such Incremental Auction pursuant to subsection (c) above) times the number of days in such Delivery Year*; and*

(ii) *For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).*

E. Price Responsive Demand Credit Rate

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (ii) $20 per MW-day) times the number of days in such Delivery Year;

b. Subsequent to the posting of the results from a Base Residual Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for Price Responsive Demand registered prior to such auction shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the PRD load is located) times the number of days in such Delivery Year times a final price uncertainty factor of 1.05;

c. For any additional Price Responsive Demand that seeks to commit in a Third Incremental Auction in response to a qualifying change in the final LDA load forecast, the Price Responsive Demand Credit Rate shall be the same as the rate for Price Responsive Demand that had cleared in the Base Residual Auction;

d. Subsequent to the posting of the results of the Third Incremental Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for all Price Responsive Demand, shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Final Zonal Capacity Price for the Locational Deliverability Area within which the Price Responsive Demand is located) times the number of days in such Delivery Year, but no greater than the Price Responsive Demand Credit Rate previously established under subsections (a), (b), or (c) of this section for such Delivery Year.

F. RPM Seller Credit - Additional Form of Unsecured Credit for RPM

In addition to the forms of credit specified elsewhere in this Attachment Q, RPM Seller Credit shall be available to Market Sellers, but solely for purposes of satisfying RPM Auction Credit Requirements. If a supplier has a history of being a net seller into PJM markets, on average, over the past 12 months, then PJMSettlement will count as available Unsecured Credit twice the average of that participant's total net monthly PJMSettlement bills over the past 12 months. This RPM Seller Credit shall be subject to the cap on available Unsecured Credit as established in Section II.F.

G. Credit Responsibility for Traded Planned RPM Capacity Resources

PJMSettlement may require that credit and financial responsibility for planned RPM Capacity Resources that are traded remain with the original party (which for these purposes, means the party bearing credit responsibility for the planned RPM Capacity Resource immediately prior to trade) unless the receiving party independently establishes consistent with the PJM credit policy, that it has sufficient credit with PJMSettlement and agrees by providing written notice to PJMSettlement that it will fully assume the credit responsibility associated with the traded planned RPM Capacity Resource.

V. FINANCIAL TRANSMISSION RIGHT AUCTIONS

A. FTR Credit Limit.

PJMSettlement will establish an FTR Credit Limit for each Participant. Participants must maintain their FTR Credit Limit at a level equal to or greater than their FTR Credit Requirement. FTR Credit Limits will be established only by a Participant providing Financial Security.

B. FTR Credit Requirement.

For each Participant with FTR activity, PJMSettlement shall calculate an FTR Credit Requirement based on FTR cost less a discounted historical value. FTR Credit Requirements shall be further adjusted by ARR credits available and by an amount based on portfolio diversification, if applicable. The requirement will be based on individual monthly exposures which are then used to derive a total requirement.

The FTR Credit Requirement shall be calculated by first adding for each month the FTR Monthly Credit Requirement Contribution for each submitted, accepted, and cleared FTR and then subtracting the prorated value of any ARRs held by the Participant for that month. The resulting twelve monthly subtotals represent the expected value of net payments between PJMSettlement and the Participant for FTR activity each month during the Planning Period. Subject to later adjustment by an amount based on portfolio diversification, if applicable, the FTR Credit Requirement shall be the sum of the individual positive monthly subtotals, representing months in which net payments to PJMSettlement are expected.

C. Rejection of FTR Bids.

Bids submitted into an auction will be rejected if the Participant's FTR Credit Requirement including such submitted bids would exceed the Participant's FTR Credit Limit, or if the Participant fails to establish additional credit as required pursuant to provisions related to portfolio diversification.

D. FTR Credit Collateral Returns.

A Market Participant may request from PJMSettlement the return of any collateral no longer required for the FTR auctions. PJMSettlement is permitted to limit the frequency of such requested collateral returns, provided that collateral returns shall be made by PJMSettlement at least once per calendar quarter, if requested by a Market Participant.

E. Credit Responsibility for Traded FTRs.

PJMSettlement may require that credit responsibility associated with an FTR traded within PJM's eFTR system remain with the original party (which for these purposes, means the party bearing credit responsibility for the FTR immediately prior to trade) unless and until the receiving party independently establishes, consistent with the PJM credit policy, sufficient credit with PJMSettlement and agrees through confirmation of the FTR trade within the eFTR system that it will meet in full the credit requirements associated with the traded FTR.

F. Portfolio Diversification.

Subsequent to calculating a tentative cleared solution for an FTR auction (or auction round), PJM shall both:

1. Determine the FTR Portfolio Auction Value, including the tentative cleared solution. Any Participants with such FTR Portfolio Auction Values that are negative shall be deemed FTR Flow Undiversified.

2. Measure the geographic concentration of the FTR Flow Undiversified portfolios by testing such portfolios using a simulation model including, one at a time, each planned

transmission outage or other network change which would substantially affect the network for the specific auction period. A list of such planned outages or changes anticipated to be modeled shall be posted prior to commencement of the auction (or auction round). Any FTR Flow Undiversified portfolio that experiences a net reduction in calculated congestion credits as a result of any one or more of such modeled outages or changes shall be deemed FTR Geographically Undiversified.

For portfolios that are FTR Flow Undiversified but not FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to twice the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For Participants with portfolios that are both FTR Flow Undiversified and FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to three times the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For portfolios that are FTR Flow Undiversified in months subsequent to the current planning year, these incremental amounts, calculated on a monthly basis, shall be reduced (but not below zero) by an amount up to 25% of the monthly value of ARR credits that are held by a Participant. Subsequent to the ARR allocation process preceding an annual FTR auction, such ARRs credits shall be reduced to zero for months associated with that ARR allocation process. PJMSettlement may recalculate such ARR credits at any time, but at a minimum shall do so subsequent to each annual FTR auction. If a reduction in such ARR credits at any time increases the amount of credit required for the Participant beyond its credit available for FTR activity, the Participant must increase its credit to eliminate the shortfall.

If the FTR Credit Requirement for any Participant exceeds its credit available for FTRs as a result of these diversification requirements for the tentatively cleared portfolio of FTRs, PJMSettlement shall immediately issue a demand for additional credit, and such demand must be fulfilled before 4:00 p.m. on the business day following the demand. If any Participant does not timely satisfy such demand, PJMSettlement, in coordination with PJM, shall cause the removal that Participant's entire set of bids for that FTR auction (or auction round) and a new cleared solution shall be calculated for the entire auction (or auction round).

If necessary, PJM shall repeat the auction clearing calculation. PJM shall repeat these portfolio diversification calculations subsequent to any such secondary clearing calculation, and PJMSettlement shall require affected Participants to establish additional credit.

G. FTR Administrative Charge Credit Requirement

In addition to any other credit requirements, PJMSettlement may apply a credit requirement to cover the maximum administrative fees that may be charged to a Participant for its bids and offers.

H. Long-Term FTR Credit Recalculation

Long-term FTR Credit Requirement calculations shall be updated annually for known history, consistent with updating of historical values used for FTR Credit Requirement calculations in the annual auctions.

VI. EXPORT TRANSACTION SCREENING

Export Transactions in the Real-time Energy Market shall be subject to Export Transaction Screening. Export Transaction Screening may be performed either for the duration of the entire Export Transaction, or separately for each time interval comprising an Export Transaction. PJM will deny or curtail all or a portion (based on the relevant time interval) of an Export Transaction if that Export Transaction, or portion thereof, would otherwise cause the Market Participant's Export Credit Exposure to exceed its Credit Available for Export Transactions. Export Transaction Screening shall be applied separately for each Operating Day and shall also be applied to each Export Transaction one or more times prior to the market clearing process for each relevant time interval. Export Transaction Screening shall not apply to transactions established directly by and between PJM and a neighboring Balancing Authority for the purpose of maintaining reliability.

A Market Participant's credit exposure for an individual Export Transaction shall be the MWh volume of the Export Transaction for each relevant time interval multiplied by each relevant Export Transaction Price Factor and summed over all relevant time intervals of the Export Transaction.

VII. FORMS OF FINANCIAL SECURITY

Participants that provide Financial Security must provide the security in a PJMSettlement approved form and amount according to the guidelines below.

Financial Security which is no longer required to be maintained under provisions of the Agreements shall be returned at the request of a participant no later than two Business Days following determination by PJMSettlement within a commercially reasonable period of time that such collateral is not required.

Except when an event of default has occurred, a Participant may substitute an approved PJMSettlement form of Financial Security for another PJMSettlement approved form of Financial Security of equal value. The Participant must provide three (3) Business Days notice to PJMSettlement of its intent to substitute the Financial Security. PJMSettlement will release the replaced Financial Security with interest, if applicable, within (3) Business Days of receiving an approved form of substitute Financial Security.

A. Cash Deposit

Cash provided by a Participant as Financial Security will be held in a depository account by PJMSettlement with interest earned at PJMSettlement's overnight bank rate, and accrued to the Participant. PJMSettlement also may establish an array of investment options among which a Participant may choose to invest its cash deposited as Financial Security. Such investment options shall be comprised of high quality debt instruments, as determined by PJMSettlement, and may include obligations issued by the federal government and/or federal government sponsored enterprises. These investment options will reside in accounts held in PJMSettlement's name in a banking or financial institution acceptable to PJMSettlement. Where practicable, PJMSettlement may establish a means for the Participant to communicate directly with the bank or financial institution to permit the Participant to direct certain activity in the PJMSettlement account in which its Financial Security is held. PJMSettlement will establish and publish procedural rules, identifying the investment options and respective discounts in collateral value that will be taken to reflect any liquidation, market and/or credit risk presented by such investments. PJMSettlement has the right to liquidate all or a portion of the account balances at its discretion to satisfy a Participant's Total Net Obligation to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

B. Letter Of Credit

An unconditional, irrevocable standby letter of credit can be utilized to meet the Financial Security requirement. As stated below, the form, substance, and provider of the letter of credit must all be acceptable to PJMSettlement.

- The letter of credit will only be accepted from U.S.-based financial institutions or U.S. branches of foreign financial institutions ("financial institutions") that have a minimum corporate debt rating of "A" by Standard & Poor's or Fitch Ratings, or "A2" from Moody's Investors Service, or an equivalent short term rating from one of these agencies. PJMSettlement will consider the lowest applicable rating to be the rating of the financial institution. If the rating of a financial institution providing a letter of credit is lowered below A/A2 by any rating agency, then PJMSettlement may require the Participant to provide a letter of credit from another financial institution that is rated A/A2 or better, or to provide a cash deposit. If a letter of credit is provided from a U.S. branch of a foreign institution, the U.S. branch must itself comply with the terms of this credit policy, including having its own acceptable credit rating.

- The letter of credit shall state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety (90) days prior written notice from the issuing financial institution. If PJM or PJMSettlement receives notice from the issuing financial institution that the current letter of credit is being cancelled, the Participant will be required to provide evidence, acceptable to PJMSettlement, that such letter of credit will be replaced with appropriate Financial Security, effective as of the cancellation date of the letter of credit, no later than thirty (30) days before the cancellation date of the letter of credit, and no later than ninety (90) days after the notice of cancellation. Failure to do so will constitute a default under this credit policy and one of more of the Agreements.

- The letter of credit must clearly state the full names of the "Issuer", "Account Party" and "Beneficiary" (PJMSettlement), the dollar amount available for drawings, and shall specify that funds will be disbursed upon presentation of the drawing certificate in accordance with the instructions stated in the letter of credit. The letter of credit should specify any statement that is required to be on the drawing certificate, and any other terms and conditions that apply to such drawings.

- The PJMSettlement Credit Application contains an acceptable form of a letter of credit that should be utilized by a Participant choosing to meet its Financial Security requirement with a letter of credit. If the letter of credit varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a letter of credit and meeting the policy provisions are the responsibility of the Participant

- PJMSettlement may accept a letter of credit from a Financial Institution that does not meet the credit standards of this policy provided that the letter of credit has third-party support, in a form acceptable to PJMSettlement, from a financial institution that does meet the credit standards of this policy.

VIII. POLICY BREACH AND EVENTS OF DEFAULT

A Participant will have two Business Days from notification of Breach (including late payment notice) or notification of a Collateral Call to remedy the Breach or satisfy the Collateral Call in a manner deemed acceptable by PJMSettlement. Failure to remedy the Breach or satisfy such Collateral Call within such two Business Days will be considered an event of default. If a Participant fails to meet the requirements of this policy but then remedies the Breach or satisfies a Collateral Call within the two Business Day cure period, then the Participant shall be deemed to have complied with the policy. Any such two Business Day cure period will expire at 4:00 p.m. eastern prevailing time on the final day.

Only one cure period shall apply to a single event giving rise to a breach or default. Application of Financial Security towards a non-payment Breach shall not be considered a satisfactory cure of the Breach if the Participant fails to meet all requirements of this policy after such application.

Failure to comply with this policy (except for the responsibility of a Participant to notify PJMSettlement of a Material change) shall be considered an event of default. Pursuant to § 15.1.3(a) of the Operating Agreement of PJM Interconnection, L.L.C. and § I.7.3 of the PJM Open Access Transmission Tariff, non-compliance with the PJMSettlement credit policy is an event of default under those respective Agreements. In event of default under this credit policy or one or more of the Agreements, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant's ongoing Transmission Service and participation in PJM Markets. PJMSettlement has the right to liquidate all or a portion of a Participant's Financial Security at its discretion to satisfy Total Net Obligations to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

PJMSettlement may hold a defaulting Participant's Financial Security for as long as such party's positions exist and consistent with the PJM credit policy in this Attachment Q, in order to protect PJM's membership from default.

No payments shall be due to a Participant, nor shall any payments be made to a Participant, while the Participant is in default or has been declared in Breach of this policy or the Agreements, or while a Collateral Call is outstanding. PJMSettlement may apply towards an ongoing default any amounts that are held or later become available or due to the defaulting Participant through PJM's markets and systems.

In order to cover Obligations, PJMSettlement may hold a Participant's Financial Security through the end of the billing period which includes the 90th day following the last day a Participant had activity, open positions, or accruing obligations (other than reconciliations and true-ups), and until such Participant has satisfactorily paid any obligations invoiced through such period. Obligations incurred or accrued through such period shall survive any withdrawal from PJM. In event of non-payment, PJMSettlement may apply such Financial Security to such Participant's Obligations, even if Participant had previously announced and effected its withdrawal from PJM.

IX. DEFINITIONS:

All capitalized terms in this Attachment Q that are not otherwise defined herein shall have the same meaning as they are defined in the Agreements.

Affiliate
Affiliate is defined in the PJM Operating Agreement, §1.2.

Agreements
Agreements are the Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, the Reliability Assurance Agreement – West, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Applicant
Applicant is an entity desiring to become a PJM Member, or to take Transmission Service that has submitted the PJMSettlement Credit Application, PJMSettlement Credit Agreement and other required submittals as set forth in this policy.

Breach
Breach is the status of a Participant that does not currently meet the requirements of this policy or other provisions of the Agreements.

Business Day
A Business Day is a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Canadian Guaranty
Canadian Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of this credit policy.

Capacity
Capacity is the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Collateral Call

Collateral Call is a notice to a Participant that additional Financial Security, or possibly early payment, is required in order to remain in, or to regain, compliance with this policy.

Corporate Guaranty
Corporate Guaranty is a legal document used by one entity to guaranty the obligations of another entity.

Credit Available for Export Transactions
Credit Available for Export Transactions is a set-aside of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions
A Market Participant's Credit Available for Virtual Transactions is the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy.

Credit-Limited Offer
Credit-Limited Offer shall mean a Sell Offer that is submitted by a Market Seller in an RPM Auction subject to a maximum credit requirement specified by such Market Seller.

Credit Score
Credit Score is a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

Export Credit Exposure
Export Credit Exposure is determined for each Market Participant for a given Operating Day, and is the sum of credit exposures for the Market Participant's Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price
The Export Nodal Reference Price at each location is the 97th percentile real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction
An Export Transaction is a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated

External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transactions Net Activity
Export Transactions Net Activity shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Export Transaction Price Factor
The Export Transaction Price Factor for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening
Export Transaction Screening is the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Financial Security
Financial Security is a cash deposit or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Foreign Guaranty
Foreign Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of this credit policy.

FTR Credit Limit
FTR Credit Limit will be equal to the amount of credit established with PJMSettlement that a Participant has specifically designated to PJMSettlement to be set aside and used for FTR activity. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the Participant may have with PJMSettlement.

FTR Credit Requirement
FTR Credit Requirement is the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or is bidding for. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems.

FTR Flow Undiversified
FTR Flow Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Geographically Undiversified
FTR Geographically Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Historical Value
FTR Historical Value – For each FTR for each month, this is the historical weighted average value over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year. FTR Historical Values shall be calculated separately for on-peak, off-peak, and 24-hour FTRs for each month of the year. FTR Historical Values shall be adjusted by plus or minus ten percent (10%) for cleared counterflow or normal flow FTRs, respectively, in order to mitigate exposure due to uncertainty and fluctuations in actual FTR value.

FTR Monthly Credit Requirement Contribution
FTR Monthly Credit Requirement Contribution - For each FTR for each month, this is the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity
FTR Net Activity shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant
FTR Participant shall mean any Market Participant that is required to provide Financial Security in order to participate in PJM's FTR auctions.

FTR Portfolio Auction Value
FTR Portfolio Auction Value shall mean for each Participant (or Participant account), the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Market Participant
Market Participant shall have the meaning provided in the Operating Agreement.

Material
For these purposes, material is defined in §I.B.3, Material Changes. For the purposes herein, the use of the term "material" is not necessarily synonymous with use of the term by governmental agencies and regulatory bodies.

Member
Member shall have the meaning provided in the Operating Agreement.

Minimum Participation Requirements
A set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM markets, as set forth herein and in the Form of Annual Certification set forth as Appendix 1 to this Attachment Q. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Appendix 1 to this Attachment Q.

Net Obligation
Net Obligation is the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position
Net Sell Position is the amount of Net Obligation when Net Obligation is negative.

Nodal Reference Price
The Nodal Reference Price at each location is the 97th percentile price differential between hourly day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. In order to capture seasonality effects and maintain a two-month reference period, reference months will be grouped by two, starting with January (e.g., Jan-Feb, Mar-Apr, … , Jul-Aug, … Nov-Dec). For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

Obligation
Obligation is all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for Capacity purchases within the PJM Capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Operating Agreement of PJM Interconnection, L.L.C., (“Operating Agreement”)
The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of June 2, 1997, on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Participant
A Participant is a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer.

Peak Market Activity
Peak Market Activity is a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of section II.D of this Credit Policy.

PJM Markets
The PJM Markets are the PJM Interchange Energy Market and the PJM Capacity markets as established by the Operating Agreement. Also any other markets that exist or may be established in the future wherein Participants may incur Obligations to PJMSettlement.

PJM Open Access Transmission Tariff ("O.A.T.T.")
The Open Access Transmission Tariff of PJM Interconnection, L.L.C., on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Reliability Assurance Agreement ("R.A.A.")
See the definition of the Reliability Assurance Agreement ("R.A.A.") in the Operating Agreement.

RPM Seller Credit
RPM Seller Credit is an additional form of Unsecured Credit defined in section IV of this document.

~~**Seller Credit**~~
~~A Seller Credit is a form of Unsecured Credit extended to Participants that have a consistent long-term history of selling into PJM Markets, as defined in this document.~~

Tangible Net Worth
Tangible Net Worth is all assets (not including any intangible assets such as goodwill) less all liabilities. Any such calculation may be reduced by PJMSettlement upon review of the available financial information.

Total Net Obligation
Total Net Obligation is all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position
Total Net Sell Position is all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Transmission Customer

Transmission Customer is a Transmission Customer is an entity taking service under Part II or Part III of the O.A.T.T.

Transmission Service
Transmission Service is any or all of the transmission services provided by PJM pursuant to Part II or Part III of the O.A.T.T.

Uncleared Bid Exposure
Uncleared Bid Exposure is a measure of exposure from Increment Offers and Decrement Bids activity relative to a Participant's established credit as defined in this policy. It is used only as a pre-screen to determine whether a Participant's Increment Offers and Decrement Bids should be subject to Increment Offer and Decrement Bid Screening.

Unsecured Credit
Unsecured Credit is any credit granted by PJMSettlement to a Participant that is not secured by a form of Financial Security.

Unsecured Credit Allowance
Unsecured Credit Allowance is Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Financial Security. See also: "Working Credit Limit."

Up-to Congestion Counterflow Transaction
An Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month
An Up-to Congestion Historical Month is a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction
An Up-to Congestion Transaction will be deemed an Up-to Congestion Prevailing Flow Transaction if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price
The Up-to Congestion Reference Price for an Up-to Congestion Transaction is the specified percentile price differential between source and sink (defined as sink price minus source price) for hourly real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30^{th} percentile

For Up-to Congestion Counterflow Transactions when bid: 20th percentile
For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Virtual Credit Exposure
Virtual Credit Exposure is the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in this policy.

Virtual Transaction Screening
Virtual Transaction Screening is the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity
Virtual Transactions Net Activity shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Virtual Transactions Net Activity may be positive or negative.

Working Credit Limit
Working Credit Limit amount is 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement. The Working Credit Limit establishes the maximum amount of Total Net Obligation that a Market Participant may have outstanding at any time. The calculation of Working Credit Limit shall take into account applicable reductions for Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Working Credit Limit for Virtual Transactions
The Working Credit Limit for Virtual Transactions shall be calculated as 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement when the Market Participant is at or below its Peak Market Activity credit requirements as specified in section II.D of this Credit Policy. When the Market Participant provides additional Unsecured Credit Allowance and/or Financial Security in excess of its Peak Market Activity credit requirements, such additional Unsecured Credit Allowance and/or Financial Security shall not be discounted by 25% when calculating the Working Credit Limit for Virtual Transactions. The Working Credit Limit for Virtual Transactions is a component in the calculation of Credit Available for Virtual Transactions. The calculation of Working Credit Limit for Virtual Transactions shall take into account applicable reductions for Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Appendix 1 to Attachment Q

PJM MINIMUM PARTICIPATION CRITERIA
OFFICER CERTIFICATION FORM

Participant Name: ____ ("Participant")

I, ____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. and PJM Settlement, Inc. (”PJMSettlement”) are relying on this certification as evidence that Participant meets the minimum requirements set forth in Attachment Q to the PJM Open Access Transmission Tariff ("PJM Tariff"), hereby certify that I have full authority to represent on behalf of Participant and further represent as follows, as evidenced by my initialing each representation in the space provided below:

1. All employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Amended and Restated Operating Agreement (“PJM Operating Agreement”) on behalf of the Participant have received appropriate[1] training and are authorized to transact on behalf of Participant._________

2. Participant has written risk management policies, procedures, and controls, approved by Participant’s independent risk management function[2] and applicable to transactions in the PJM markets in which it participates and for which employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Operating Agreement have been trained, that provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Participant is exposed, including, but not limited to credit risks, liquidity risks and market risks.__________

3. An FTR Participant (as defined in Attachment Q to the PJM Tariff) must make either the following 3.a. or 3.b. additional representations, evidenced by the undersigned officer initialing either the one 3.a. representation or the six 3.b. representations in the spaces provided below:

   3.a. Participant transacts in PJM’s FTR markets with the sole intent to hedge congestion risk in connection with either obligations Participant has to serve load or rights Participant has to generate electricity in the PJM Region (“physical

[1] As used in this representation, the term “appropriate” as used with respect to training means training that is (i) comparable to generally accepted practices in the energy trading industry, and (ii) commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the participant.

[2] As used in this representation, a Participant’s “independent risk management function” can include appropriate corporate persons or bodies that are independent of the Participant’s trading functions, such as a risk management committee, a risk officer, a Participant’s board or board committee, or a board or committee of the Participant’s parent company.

transactions") and monitors all of the Participant's FTR market activity to endeavor to ensure that its FTR positions, considering both the size and pathways of the positions, are either generally proportionate to or generally do not exceed the Participant's physical transactions, and remain generally consistent with the Participant's intention to hedge its physical transactions.__________

3.b. On no less than a weekly basis, Participant values its FTR positions and engages in a probabilistic assessment of the hypothetical risk of such positions using analytically based methodologies, predicated on the use of industry accepted valuation methodologies.__________

Such valuation and risk assessment functions are performed either by persons within Participant's organization independent from those trading in PJM's FTR markets or by an outside firm qualified and with expertise in this area of risk management.__________

Having valued its FTR positions and quantified their hypothetical risks, Participant applies its written policies, procedures and controls to limit its risks using industry recognized practices, such as value-at-risk limitations, concentration limits, or other controls designed to prevent Participant from purposefully or unintentionally taking on risk that is not commensurate or proportional to Participant's financial capability to manage such risk.__________

Exceptions to Participant's written risk policies, procedures and controls applicable to Participant's FTR positions are documented and explain a reasoned basis for the granting of any exception.__________

Participant has provided to PJMSettlement, in accordance with Section I A. of Attachment Q to the PJM Tariff, a copy of its current governing risk management policies, procedures and controls applicable to its FTR trading activities.__________

If the risk management policies, procedures and controls applicable to Participant's FTR trading activities submitted to PJMSettlement were submitted prior to the current certification, Particpant certifies that no substantive changes have been made to such policies, procedures and controls applicable to its FTR trading activities since such submission.__________

4. Participant has appropriate personnel resources, operating procedures and technical abilities to promptly and effectively respond to all PJM communications and directions.__________

5. Participant has demonstrated compliance with the Minimum Capitalization criteria set forth in Attachment Q of the PJM Open Access Transmission Tariff that are applicable to the PJM market(s) in which Participant transacts, and is not aware of any change having occurred or being imminent that would invalidate such compliance.__________

6. All Participants must certify and initial in at least one of the four sections below:

   a. I certify that Participant qualifies as an "appropriate person" as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act or an "eligible contract participant" as that term is defined under Section 1a(18), or successor provision, of the Commodity Exchange Act. I certify that Participant will cease transacting in PJM's Markets and notify PJMSettlement immediately if Participant no longer qualifies as an "appropriate person" or "eligible contract participant."___________

      If providing financial statements to support Participant's certification of qualification as an "appropriate person:"

      I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $5 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.___________

      If providing financial statements to support Participant's certification of qualification as an "eligible contract participant:"

      I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $10 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.___________

   b. I certify that Participant has provided an unlimited Corporate Guaranty in a form acceptable to PJM as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant per Participant for which the issuer has issued an unlimited Corporate Guaranty. I certify that Participant will cease transacting PJM's Markets and notify PJMSettlement immediately if issuer of the unlimited Corporate Guaranty for Participant no longer has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty.___________

I certify that the issuer of the unlimited Corporate Guaranty to Participant continues to have at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty. I acknowledge that PJM and PJMSettlement are relying upon my certifications to maintain compliance with federal regulatory requirements.__________

c. I certify that Participant fulfills the eligibility requirements of the Commodity Futures Trading Commission exemption order (78 F.R. 19880 – April 2, 2013) by being in the business of at least one of the following in the PJM Region as indicated below (initial those applicable):

1. Generating electric energy, including Participants that resell physical energy acquired from an entity generating electric energy:__________

2. Transmitting electric energy:__________

3. Distributing electric energy delivered under Point-to-Point or Network Integration Transmission Service, including scheduled import, export and wheel through transactions:__________

4. Other electric energy services that are necessary to support the reliable operation of the transmission system:__________

Description only if c(4) is initialed:

____

Further, I certify that Participant will cease transacting in PJM's Markets and notify PJMSettlement immediately if Participant no longer performs at least one of the functions noted above in the PJM Region. I acknowledge that PJM and PJMSettlement are relying on my certification to maintain compliance with federal energy regulatory requirements.__________

d. I certify that Participant has provided a letter of credit of $5 million or more to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Participant acknowledges cannot be utilized to meet its credit requirements to PJMSettlement. I acknowledge that PJM and PJMSettlement are relying on the provision of this letter of credit and my certification to maintain compliance with federal regulatory requirements.__________

7. I acknowledge that I have read and understood the provisions of Attachment Q of the PJM Tariff applicable to Participant's business in the PJM markets, including those provisions describing PJM's minimum participation requirements and the enforcement actions available to PJMSettlement of a Participant not satisfying those requirements. I acknowledge that the information provided herein is true and accurate to the best of my belief and knowledge after due investigation. In addition, by signing this Certification, I

acknowledge the potential consequences of making incomplete or false statements in this Certification.___________

Date: ______________________________ ____________________________________

(Signature)

Print Name: ____________________________________

Title: ____________________________________

ATTACHMENT Q

PJM CREDIT POLICY

POLICY STATEMENT:

It is the policy of PJM Interconnection, LLC ("PJM") that prior to an entity participating in the PJM Markets, or in order to take Transmission Service, the entity must demonstrate its ability to meet PJMSettlement's credit requirements.

Prior to becoming a Market Participant, Transmission Customer, and/or Member of PJM, PJMSettlement must accept and approve a Credit Application (including Credit Agreement) from such entity and establish a Working Credit Limit with PJMSettlement. PJMSettlement shall approve or deny an accepted Credit Application on the basis of a complete credit evaluation including, but not be limited to, a review of financial statements, rating agency reports, and other pertinent indicators of credit strength.

POLICY INTENT:

This credit policy describes requirements for: (1) the establishment and maintenance of credit by Market Participants, Transmission Customers, and entities seeking either such status (collectively "Participants"), pursuant to one or more of the Agreements, and (2) forms of security that will be deemed acceptable (hereinafter the "Financial Security") in the event that the Participant does not satisfy the financial or other requirements to establish Unsecured Credit.

This policy also sets forth the credit limitations that will be imposed on Participants in order to minimize the possibility of failure of payment for services rendered pursuant to the Agreements, and conditions that will be considered an event of default pursuant to this policy and the Agreements.

These credit rules may establish certain set-asides of credit for designated purposes (such as for FTR or RPM activity). Such set-asides shall be construed to be applicable to calculation of credit requirements only, and shall not restrict PJMSettlement's ability to apply such designated credit to any obligation(s) in case of a default.

PJMSettlement may post on PJM's web site, and may reference on OASIS, a supplementary document which contains additional business practices (such as algorithms for credit scoring) that are not included in this document. Changes to the supplementary document will be subject to stakeholder review and comment prior to implementation. PJMSettlement may specify a required compliance date, not less than 15 days from notification, by which time all Participants must comply with provisions that have been revised in the supplementary document.

APPLICABILITY:

This policy applies to all Participants.

IMPLEMENTATION:

I. CREDIT EVALUATION

Each Participant will be subject to a complete credit evaluation in order for PJMSettlement to determine creditworthiness and to establish an **Unsecured Credit Allowance**, if applicable; provided, however, that a Participant need not provide the information specified in section I.A or I.B if it notifies PJMSettlement in writing that it does not seek any Unsecured Credit Allowance. PJMSettlement will identify any necessary Financial Security requirements and establish a Working Credit Limit for each Participant. In addition, PJMSettlement will perform follow-up credit evaluations on at least an annual basis.

If a **Corporate Guaranty** is being utilized to establish credit for a Participant, the guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

PJMSettlement will provide a Participant, upon request, with a written explanation for any change in credit levels or collateral requirements. PJMSettlement will provide such explanation within ten Business Days.

If a Participant believes that either its level of unsecured credit or its collateral requirement has been incorrectly determined, according to this credit policy, then the Participant may send a request for reconsideration in writing to PJMSettlement. Such a request should include:

- A citation to the applicable section(s) of the PJMSettlement credit policy along with an explanation of how the respective provisions of the credit policy were not carried out in the determination as made

- A calculation of what the Participant believes should be the correct credit level or collateral requirement, according to terms of the credit policy

PJMSettlement will reconsider the determination and will provide a written response as promptly as practical, but no longer than ten Business Days of receipt of the request. If the Participant still feels that the determination is incorrect, then the Participant may contest that determination. Such contest should be in written form, addressed to PJMSettlement, and should contain:

- ♦ A complete copy of the Participant's earlier request for reconsideration, including citations and calculations

- ♦ A copy of PJMSettlement's written response to its request for reconsideration

- ♦ An explanation of why it believes that the determination still does not comply with the credit policy

PJMSettlement will investigate and will respond to the Participant with a final determination on the matter as promptly as practical, but no longer than 20 Business Days.

Neither requesting reconsideration nor contesting the determination following such request shall relieve or delay Participant's responsibility to comply with all provisions of this credit policy.

A. Initial Credit Evaluation

In completing the initial credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit with its application audited financial statements for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the Participant, if shorter. All financial and related information considered for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement.

The information should include, but not be limited to, the following:

a. If publicly traded:
   - i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
   - ii. Form 8-K reports disclosing Material changes, if any.

b. If privately held:
   - i. Management's Discussion & Analysis
   - ii. Report of Independent Accountants
   - iii. Financial Statements, including:
     - Balance Sheet
     - Income Statement
     - Statement of Cash Flows
     - Statement of Stockholder's Equity
   - iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) References

PJMSettlement may request Participants to provide with their applications at least one (1) bank and three (3) utility credit references. In the case where a Participant does not have the required utility references, trade payable vendor references may be substituted.

4) Litigation, Commitments and Contingencies

Each Participant is also required to provide with its application information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJMSettlement or are applying for membership with PJMSettlement. Each Participant is also required to disclose the existence of any ongoing investigations by the Securities and Exchange Commission ("SEC"), Federal Energy Regulatory Commission ("FERC"), Commodity Futures Trading Commission ("CFTC"), or any other governing, regulatory, or standards body. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

B. Ongoing Credit Evaluation

On at least an annual basis, PJMSettlement will perform follow-up credit evaluations on all Participants. In completing the credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit audited annual financial statements as soon as they become available and no later than 120 days after fiscal year end. Each Participant is also required to provide PJMSettlement with quarterly financial statements promptly upon their issuance, but no later than 60 days after the end of each quarter. All financial and related information considered

for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement. If financial statements are not provided within the timeframe required, the Participant may not be granted an Unsecured Credit Allowance.

The information should include, but not be limited to, the following:

a. If publicly traded:
   i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
   ii. Form 8-K reports disclosing Material changes, if any, immediately upon issuance.

b. If privately held:
   i. Management's Discussion & Analysis
   ii. Report of Independent Accountants
   iii. Financial Statements, including:
      - Balance Sheet
      - Income Statement
      - Statement of Cash Flows
      - Statement of Stockholder's Equity
   iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) Material Changes

Each Participant is responsible for informing PJMSettlement immediately, in writing, of any Material change in its financial condition. However, PJMSettlement may also independently establish from available information that a Participant has experienced a Material change in its financial condition without regard to whether such Participant has informed PJMSettlement of the same.

For the purpose of this policy, a Material change in financial condition may include, but not be limited to, any of the following:

a. a downgrade of any debt rating by any rating agency;
b. being placed on a credit watch with negative implications by any rating agency;
c. a bankruptcy filing;
d. insolvency;

e. a report of a quarterly or annual loss or a decline in earnings of ten percent or more compared to the prior period;

f. restatement of prior financial statements;

g. the resignation of key officer(s);

h. the filing of a lawsuit that could adversely impact any current or future financial results by ten percent or more;

i. financial default in another organized wholesale electric market futures exchange or clearing house;

j. revocation of a license or other authority by any Federal or State regulatory agency; where such license or authority is necessary or important to the Participants continued business for example, FERC market-based rate authority, or State license to serve retail load; or

k. a significant change in credit default spreads, market capitalization, or other market-based risk measurement criteria, such as a recent increase in Moody's KMV Expected Default Frequency (EDF^{tm}) that is noticeably greater than the increase in its peers' EDF^{tm} rates, or a collateral default swap (CDS) premium normally associated with an entity rated lower than investment grade.

If PJMSettlement determines that a Material change in the financial condition of the Participant has occurred, it may require the Participant to provide Financial Security within two Business Days, in an amount and form approved by PJMSettlement. If the Participant fails to provide the required Financial Security, the Participant shall be in default under this credit policy.

In the event that PJMSettlement determines that a Material change in the financial condition of a Participant warrants a requirement to provide Financial Security, PJMSettlement shall provide the Participant with a written explanation of why such determination was made. However, under no circumstances shall the requirement that a Participant provide the requisite Financial Security be deferred pending the issuance of such written explanation.

4) Litigation, Commitments, and Contingencies

Each Participant is also required to provide information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon initiation or change or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJM or are applying for membership within PJM. Each Participant is also required to disclose the existence of any ongoing investigations by the SEC, FERC, CFTC or any other governing, regulatory, or standards body. These disclosures shall be made upon initiation or change, or as requested by PJMSettlement.

C. Corporate Guaranty

If a Corporate Guaranty is being utilized to establish credit for a Participant, the Guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

An irrevocable and unconditional Corporate Guaranty may be utilized as part of the credit evaluation process, but will not be considered a form of Financial Security. The Corporate Guaranty will be considered a transfer of credit from the Guarantor to the Participant. The Corporate Guaranty must guarantee the (i) full and prompt payment of all amounts payable by the Participant under the Agreements, and (ii) performance by the Participant under this policy.

The Corporate Guaranty should clearly state the identities of the "Guarantor," "Beneficiary" (PJMSettlement) and "Obligor" (Participant). The Corporate Guaranty must be signed by an officer of the Guarantor, and must demonstrate that it is duly authorized in a manner acceptable to PJMSettlement. Such demonstration may include either a Corporate Seal on the Guaranty itself, or an accompanying executed and sealed Secretary's Certificate noting that the Guarantor was duly authorized to provide such Corporate Guaranty and that the person signing the Corporate Guaranty is duly authorized, or other manner acceptable to PJMSettlement.

A Participant supplying a Corporate Guaranty must provide the same information regarding the Guarantor as is required in the "Initial Credit Evaluation" §I.A. and the "Ongoing Evaluation" §I.B. of this policy, including providing the Rating Agency Reports, Financial Statements and Related Information, References, Litigation Commitments and Contingencies, and Other Disclosures. A Participant supplying a Foreign or Canadian Guaranty must also satisfy the requirements of §I.C.1 or §I.C.2, as appropriate.

If there is a Material change in the financial condition of the Guarantor or if the Corporate Guaranty comes within 30 days of expiring without renewal, the Participant will be required to provide Financial Security either in the form of a cash deposit or a letter of credit. Failure to provide the required Financial Security within two Business Days after request by PJMSettlement will constitute an event of default under this credit policy. A Participant may request PJMSettlement to perform a credit evaluation in order to determine creditworthiness and to establish an Unsecured Credit Allowance, if applicable. If PJMSettlement determines that a Participant does qualify for a sufficient Unsecured Credit Allowance, then Financial Security will not be required.

The PJMSettlement Credit Application contains an acceptable form of Corporate Guaranty that should be utilized by a Participant choosing to establish its credit with a Corporate Guaranty. If the Corporate Guaranty varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a Corporate Guaranty and meeting the policy provisions are the responsibility of the Participant.

1) Foreign Guaranties

A Foreign Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in a country other than the United States or Canada. The entity providing a Foreign Guaranty on behalf of a Participant is a Foreign Guarantor. A Participant may provide a Foreign

Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met:

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Foreign Guaranty at any time, including for material adverse circumstances or occurrences.

a. A Foreign Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.
   iv. Will not be accepted towards a Participant's Unsecured Credit Allowance for more than the following limits, depending on the Foreign Guarantor's credit rating:

Rating of Foreign Guarantor	Maximum Accepted Guaranty if Country Rating is AAA	Maximum Accepted Guaranty if Country Rating is AA+
A- and above	USD50,000,000	USD30,000,000
BBB+	USD30,000,000	USD20,000,000
BBB	USD10,000,000	USD10,000,000
BBB- or below	USD 0	USD 0

   v. May not exceed 50% of the Participant's total credit, if the Foreign Grantor is rated less than BBB+.

b. A Foreign Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Foreign Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must have a Senior Unsecured (or equivalent, in PJMSettlement's sole discretion) rating of BBB (one notch above BBB-) or greater by any and all agencies that provide rating coverage of the entity.
   vi. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance

vii. Must provide a Secretary's Certificate certifying the adoption of Corporate Resolutions:
    1. Authorizing and approving the Guaranty; and
    2. Authorizing the Officers to execute and deliver the Guaranty on behalf of the Guarantor.

viii. Must be domiciled in a country with a minimum long-term sovereign (or equivalent) rating of AA+/Aa1, with the following conditions:
    1. Sovereign ratings must be available from at least two rating agencies acceptable to PJMSettlement (e.g. S&P, Moody's, Fitch, DBRS).
    2. Each agency's sovereign rating for the domicile will be considered to be the lowest of: country ceiling, senior unsecured government debt, long-term foreign currency sovereign rating, long-term local currency sovereign rating, or other equivalent measures, at PJMSettlement's sole discretion.
    3. Whether ratings are available from two or three agencies, the lowest of the two or three will be used.

ix. Must be domiciled in a country that recognizes and enforces judgments of US courts.

x. Must demonstrate financial commitment to activity in the United States as evidenced by one of the following:
    1. American Depository Receipts (ADR) are traded on the New York Stock Exchange, American Stock Exchange, or NASDAQ.
    2. Equity ownership worth over USD100,000,000 in the wholly-owned or majority owned subsidiaries in the United States.

xi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this credit policy.

xii. Must pay for all expenses incurred by PJMSettlement related to reviewing and accepting a foreign guaranty beyond nominal in-house credit and legal review.

xiii. Must, at its own cost, provide PJMSettlement with independent legal opinion from an attorney/solicitor of PJMSettlement's choosing and licensed to practice law in the United States and/or Guarantor's domicile, in form and substance acceptable to PJMSettlement in its sole discretion, confirming the enforceability of the Foreign Guaranty, the Guarantor's legal authorization to grant the Guaranty, the conformance of the Guaranty, Guarantor, and Guarantor's domicile to all of these requirements, and such other matters as PJMSettlement may require in its sole discretion.

2) Canadian Guaranties

A Canadian Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in Canada and satisfies all of the provisions below. The entity providing a Canadian Guaranty on behalf of a Participant is a Canadian Guarantor. A Participant may provide a Canadian Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met.

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Canadian Guaranty at any time for reasonable cause, including adverse material circumstances.

a. A Canadian Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.

b. A Canadian Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Canadian Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance.

   vi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Credit Policy.

Ia. MINIMUM PARTICIPATION REQUIREMENTS

A. PJM Market Participation Eligibility Requirements

To be eligible to transact in PJM Markets, a Market Participant must demonstrate in accordance with the Risk Management and Verification processes set forth below that it qualifies in one of the following ways:

1. an "appropriate person," as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act, or;

2. an "eligible contract participant," as that term is defined in Section 1a(18), or successor provision, of the Commodity Exchange Act, or;

3. a business entity or person who is in the business of: (1) generating, transmitting, or distributing electric energy, or (2) providing electric energy services that are necessary to support the reliable operation of the transmission system, or;

4. a Market Participant seeking eligibility as an "appropriate person" providing an unlimited Corporate Guaranty in a form acceptable to PJMSettlement as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty, or;

5. a Market Participant providing a letter of credit of at least $5 million to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJMSettlement.

If, at any time, a Market Participant cannot meet the eligibility requirements set forth above, it shall immediately notify PJMSettlement and immediately cease conducting transactions in the PJM Markets. PJMSettlement shall terminate a Market Participant's transaction rights in the PJM Markets if, at any time, it becomes aware that the Market Participant does not meet the minimum eligibility requirements set forth above.

In the event that a Market Participant is no longer able to demonstrate it meets the minimum eligibility requirements set forth above, and possesses, obtains or has rights to possess or obtain, any open or forward positions in PJM's Markets, PJMSettlement may take any such action it deems necessary with respect to such open or forward positions, including, but not limited to, liquidation, transfer, assignment or sale; provided, however, that the Market Participant will, notwithstanding its ineligibility to participate in the PJM Markets, be entitled to any positive market value of those positions, net of any obligations due and owing to PJM and/or PJMSettlement.

B. Risk Management and Verification

All Participants shall provide to PJMSettlement an executed copy of the annual certification set forth in Appendix 1 to this Attachment Q. This certification shall be provided before an entity is eligible to participate in the PJM Markets and shall be initially submitted to PJMSettlement together with the entity's Credit Application. Thereafter, it shall be submitted each calendar year by all Participants during a period beginning on January 1 and ending April 30, except that new Participants who became eligible to participate in PJM markets during the period of January through April shall not be required to resubmit such certification until the following calendar year. Except for certain FTR Participants (discussed below) or in cases of manifest error, PJMSettlement will accept such certifications as a matter of course and Participants will not need further notice from PJMSettlement before commencing or maintaining their eligibility to participate in PJM markets. A Participant that fails to provide its annual certification by April 30 shall be ineligible to transact in the PJM markets and PJM will disable the Participant's access to the PJM markets until such time as PJMSettlement receives the Participant's certification.

Participants acknowledge and understand that the annual certification constitutes a representation upon which PJMSettlement will rely. Such representation is additionally made under the PJM Tariff, filed with and accepted by FERC, and any inaccurate or incomplete statement may subject the Participant to action by FERC. Failure to comply with any of the criteria or

requirements listed herein or in the certification may result in suspension of a Participant's transaction rights in the PJM markets.

Certain FTR Participants (those providing representations found in paragraph 3.b of the annual certification set forth in Appendix 1 to this Attachment Q) are additionally required to submit to PJMSettlement (at the time they make their annual certification) a copy of their current governing risk control policies, procedures and controls applicable to their FTR trading activities, except that if no substantive changes have been made to such policies, practices and/or controls applicable to their FTR trading activities, they may instead submit to PJMSettlement a certification stating that no changes have been made. PJMSettlement will review such documentation to verify that it appears generally to conform to prudent risk management practices for entities trading in FTR-type markets. If principles or best practices relating to risk management in FTR-type markets are published, as may be modified from time to time, by a third-party industry association, such as the Committee of Chief Risk Officers, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the fundamental sufficiency of the FTR Participant's risk controls. Those FTR Participants subject to this provision shall make a one-time payment of $1,000.00 to PJMSettlement to cover costs associated with review and verification. Thereafter, if such FTR Participant's risk policies, procedures and controls applicable to its FTR trading activities change substantively, it shall submit such modified documentation, without charge, to PJMSettlement for review and verification at the time it makes its annual certification. Such FTR Participant's continued eligibility to participate in the PJM FTR markets is conditioned on PJMSettlement notifying such FTR Participant that its annual certification, including the submission of its risk policies, procedures and controls, has been accepted by PJMSettlement. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph, however, in all circumstances, PJMSettlement and any third-party it may retain will treat as confidential the documentation provided by an FTR Participant under this paragraph, consistent with the applicable provisions of PJM's Operating Agreement.

An FTR Participant that makes the representation in paragraph 3.a of the annual certification understand that PJMSettlement, given the visibility it has over a Participant's overall market activity in performing billing and settlement functions, may at any time request the FTR Participant provide additional information demonstrating that it is in fact eligible to make the representation in paragraph 3.a of the annual certification. If such additional information is not provided or does not, in PJMSettlement's judgment, demonstrate eligibility to make the representation in paragraph 3.a of the annual certification, PJMSettlement will require the FTR Participant to instead make the representations required in paragraph 3.b of the annual certification, including representing that it has submitted a copy of its current governing risk control policies, procedures and controls applicable to its FTR trading activities. If the FTR Participant cannot or does not make those representations as required in paragraph 3.b of the annual certification, then PJM will terminate the FTR Participant's rights to purchase FTRs in the FTR market and may terminate the FTR Participant's rights to sell FTRs in the PJM FTR market.

PJMSettlement shall also conduct a periodic compliance verification process to review and verify, as applicable, Participants' risk management policies, practices, and procedures pertaining to the Participants' activities in the PJM markets. Such review shall include verification that:

1. The risk management framework is documented in a risk policy addressing market, credit and liquidity risks.
2. The Participant maintains an organizational structure with clearly defined roles and responsibilities that clearly segregates trading and risk management functions.
3. There is clarity of authority specifying the types of transactions into which traders are allowed to enter.
4. The Participant has requirements that traders have adequate training relative to their authority in the systems and PJM markets in which they transact.
5. As appropriate, risk limits are in place to control risk exposures.
6. Reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization.
7. Processes are in place for qualified independent review of trading activities.
8. As appropriate, there is periodic valuation or mark-to-market of risk positions.

If principles or best practices relating to risk management in PJM-type markets are published, as may be modified from time to time, by a third-party industry association, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the sufficiency of the Participant's risk controls. PJMSettlement may select Participants for review on a random basis and/or based on identified risk factors such as, but not limited to, the PJM markets in which the Participant is transacting, the magnitude of the Participant's transactions in the PJM markets, or the volume of the Participant's open positions in the PJM markets. Those Participants notified by PJMSettlement that they have been selected for review shall, upon 14 calendar days notice, provide a copy of their current governing risk control policies, procedures and controls applicable to their PJM market activities and shall also provide such further information or documentation pertaining to the Participants' activities in the PJM markets as PJMSettlement may reasonably request. Participants selected for risk management verification through a random process and satisfactorily verified by PJMSettlement shall be excluded from such verification process based on a random selection for the subsequent two years. PJMSettlement shall annually randomly select for review no more than 20% of the Participants in each member sector.

Each selected Participant's continued eligibility to participate in the PJM markets is conditioned upon PJMSettlement notifying the Participant of successful completion of PJMSettlement's verification of the Participant's risk management policies, practices and procedures, as discussed

herein. However, if PJMSettlement notifies the Participant in writing that it could not successfully complete the verification process, PJMSettlement shall allow such Participant 14 calendar days to provide sufficient evidence for verification prior to declaring the Participant as ineligible to continue to participate in PJM's markets, which declaration shall be in writing with an explanation of why PJMSettlement could not complete the verification. If, prior to the expiration of such 14 calendar days, the Participant demonstrates to PJMSettlement that it has filed with the Federal Energy Regulatory Commission an appeal of PJMSettlement's risk management verification determination, then the Participant shall retain its transaction rights, pending the Commission's determination on the Participant's appeal. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph. PJMSettlement and any third party it may retain will treat as confidential the documentation provided by a Participant under this paragraph, consistent with the applicable provisions of the Operating Agreement. If PJMSettlement retains such outside expertise, a Participant may direct in writing that PJMSettlement perform the risk management review and verification for such Participant instead of utilizing a third party, provided however, that employees and contract employees of PJMSettlement and PJM shall not be considered to be such outside expertise or third parties.

Participants are solely responsible for the positions they take and the obligations they assume in PJM markets. PJMSettlement hereby disclaims any and all responsibility to any Participant or PJM Member associated with Participant's submitting or failure to submit its annual certification or PJMSettlement's review and verification of an FTR Participant's risk policies, procedures and controls. Such review and verification is limited to demonstrating basic compliance by an FTR Participant with the representation it makes under paragraph 3.b of its annual certification showing the existence of written policies, procedures and controls to limit its risk in PJM's FTR markets and does not constitute an endorsement of the efficacy of such policies, procedures or controls.

C. Capitalization

In addition to the Annual Certification requirements in Appendix 1 to this Attachment Q, a Participant must demonstrate that it meets the minimum financial requirements appropriate for the PJM market(s) in which it transacts by satisfying either the Minimum Capitalization or the Provision of Collateral requirements listed below:

1. Minimum Capitalization

FTR Participants must demonstrate a tangible net worth in excess of $1 million or tangible assets in excess of $10 million. Other Participants must demonstrate a tangible net worth in excess of $500,000 or tangible assets in excess of $5 million.

a. In either case, consideration of "tangible" assets and net worth shall exclude assets (net of any matching liabilities, assuming the result is a positive value) which PJMSettlement reasonably believes to be restricted, highly risky, or potentially unavailable to settle a claim in the event of default. Examples include, but are not

limited to, restricted assets and Affiliate assets, derivative assets, goodwill, and other intangible assets.

b. Demonstration of "tangible" assets and net worth may be satisfied through presentation of an acceptable Corporate Guaranty, provided that both:

(i) the guarantor is an affiliate company that satisfies the tangible net worth or tangible assets requirements herein, and;

(ii) the Corporate Guaranty is either unlimited or at least $500,000.

If the Corporate Guaranty presented by the Participant to satisfy these Capitalization requirements is limited in value, then the Participant's resulting Unsecured Credit Allowance shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this Credit Policy, or:

(2) the face value of the Corporate Guaranty, reduced by $500,000 and further reduced by 10%. (For example, a $10.5 million Corporate Guaranty would be reduced first by $500,000 to $10 million and then further reduced 10% more to $9 million. The resulting $9 million would be the Participant's Unsecured Credit Allowance available through the Corporate Guaranty).

In the event that a Participant provides collateral in addition to a limited Corporate Guaranty to increase its available credit, the value of such collateral shall be reduced by 10%. This reduced value shall be deemed Financial Security and available to satisfy the requirements of this Credit Policy.

Demonstrations of capitalization must be presented in the form of audited financial statements for the Participant's most recent fiscal year.

2. Provision of Collateral

If a Participant does not demonstrate compliance with its applicable Minimum Capitalization Requirements above, it may still qualify to participate in PJM's markets by posting additional collateral, subject to the terms and conditions set forth herein.

Any collateral provided by a Participant unable to satisfy the Minimum Capitalization Requirements above will be restricted in the following manner:

i. Collateral provided by FTR Participants shall be reduced by $500,000 and then further reduced by 10%. This reduced amount shall be considered the Financial Security provided by the Participant and available to satisfy requirements of this Credit Policy.

ii. Collateral provided by other Participants that engage in Virtual Transactions or Export Transactions shall be reduced by $200,000 and then further reduced by 10%. This reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

iii. Collateral provided by other Participants that do not engage in Virtual Transactions or Export Transactions shall be reduced by 10%, and this reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

In the event a Participant that satisfies the Minimum Participation Requirements through provision of collateral also provides a Corporate Guaranty to increase its available credit, then the Participant's resulting Unsecured Credit Allowance conveyed through such Guaranty shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this credit policy, or,

(2) the face value of the Guaranty, reduced by 10%.

II. CREDIT ALLOWANCE AND WORKING CREDIT LIMIT

PJMSettlement's credit evaluation process will include calculating a Credit Score for each Participant. The credit score will be utilized to determine a Participant's Unsecured Credit Allowance.

Participants who do not qualify for an Unsecured Credit Allowance will be required to provide Financial Security based on their Peak Market Activity, as provided below.

A corresponding Working Credit Limit will be established based on the Unsecured Credit Allowance and/or the Financial Security provided.

Where Participant of PJM are considered Affiliates, Unsecured Credit Allowances and Working Credit Limits will be established for each individual Participant, subject to an aggregate maximum amount for all Affiliates as provided for in §II.F of this policy.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

A. Credit Score

For participants with credit ratings, a Credit Score will be assigned based on their senior unsecured credit rating and credit watch status as shown in the table below. If an explicit senior unsecured rating is not available, PJMSettlement may impute an equivalent rating from other ratings that are available. For Participants without a credit rating, but who wish to be considered for unsecured Credit, a Credit Score will be generated from PJMSettlement's review and analysis of various factors that are predictors of financial strength and creditworthiness. Key factors in the scoring process include, financial ratios, and years in business. PJMSettlement will consistently apply the measures it uses in determining Credit Scores. The credit scoring methodology details are included in a supplementary document available on OASIS.

Rated Entities Credit Scores

Rating	Score	Score Modifier	
		Credit Watch Negative	Credit Watch Positive
AAA	100	-1.0	0.0
AA+	99	-1.0	0.0
AA	99	-1.0	0.0
AA-	98	-1.0	0.0
A+	97	-1.0	0.0
A	96	-2.0	0.0
A-	93	-3.0	1.0
BBB+	88	-4.0	2.0
BBB	78	-4.0	2.0
BBB-	65	-4.0	2.0
BB+ and below	0	0.0	0.0

B. Unsecured Credit Allowance

PJMSettlement will determine a Participant's Unsecured Credit Allowance based on its Credit Score and the parameters in the table below. The maximum Unsecured Credit Allowance is the lower of:

1) A percentage of the Participant's Tangible Net Worth, as stated in the table below, with the percentage based on the Participant's credit score; and

2) A dollar cap based on the credit score, as stated in the table below:

Credit Score	Tangible Net Worth Factor	Maximum Unsecured Credit Allowance ($ Million)
91-100	2.125 – 2.50%	$50
81-90	1.708 – 2.083%	$42
71-80	1.292 – 1.667%	$33
61-70	0.875 – 1.25%	$7
51-60	0.458 – 0.833%	$0-$2
50 and Under	0%	$0

If a Corporate Guaranty is utilized to establish an Unsecured Credit Allowance for a Participant, the value of a Corporate Guaranty will be the lesser of:

- The limit imposed in the Corporate Guaranty;
- The Unsecured Credit Allowance calculated for the Guarantor; and
- A portion of the Unsecured Credit Allowance calculated for the Guarantor in the case of Affiliated Participants.

PJMSettlement has the right at any time to modify any Unsecured Credit Allowance and/or require additional Financial Security as may be deemed reasonably necessary to support current market activity. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.

PJMSettlement will maintain a posting of each Participant's unsecured Credit Allowance, along with certain other credit related parameters, on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

C. Seller Credit

Participants that have maintained a Net Sell Position for each of the prior 12 months are eligible for Seller Credit, which is an additional form of Unsecured Credit. A Participant's Seller Credit will be equal to sixty percent of the Participant's thirteenth smallest weekly Net Sell Position invoiced in the past 52 weeks.

Each Participant receiving Seller Credit must maintain both its Seller Credit and its Total Net Sell Position equal to or greater than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided.

For Participants receiving Seller Credit, PJMSettlement may forecast the Participant's Total Net Sell Position considering the Participant's current Total Net Sell Position, recent trends in the Participant's Total Net Sell Position, and other information available to PJMSettlement, such as, but not limited to, known generator outages, changes in load responsibility, and bilateral

transactions impacting the Participant. If PJMSettlement's forecast ever indicates that the Participant's Total Net Sell Position may in the future be less than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided, then PJMSettlement may require Financial Security as needed to cover the difference. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.

Any Financial Security required by PJMSettlement pursuant to these provisions for Seller Credit will be returned once the requirement for such Financial Security has ended. Seller Credit may not be conveyed to another entity through use of a guaranty. Seller Credit shall be subject to the cap on available Unsecured Credit set forth in Section II.F.

D. Peak Market Activity and Financial Security Requirement

A PJM Participant or Applicant that has an insufficient Unsecured Credit Allowance to satisfy its Peak Market Activity will be required to provide Financial Security such that its Unsecured Credit Allowance and Financial Security together are equal to its Peak Market Activity in order to secure its transactional activity in the PJM Market.

Peak Market Activity for Participants will be determined semi-annually beginning in the first complete billing week in the months of April and October. Peak Market Activity shall be the greater of the initial Peak Market Activity, as explained below, or the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two, or three week period, ending within a respective semi-annual period. However, Peak Market Activity shall not exceed the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two or three week period in the prior 52 weeks.

Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

The initial Peak Market Activity for Applicants will be determined by PJMSettlement based on a review of an estimate of their transactional activity for all PJM markets and services over the next 52 weeks, which the Applicant shall provide to PJMSettlement.

The initial Peak Market Activity for Participants, calculated at the beginning of each respective semi-annual period, shall be the three-week average of all non-zero invoice totals over the previous 52 weeks. This calculation shall be performed and applied within three business days following the day the invoice is issued for the first full billing week in the current semi-annual period.

Prepayments shall not affect Peak Market Activity unless otherwise agreed to in writing pursuant to this Credit Policy.

All Peak Market Activity calculations shall take into account reductions of invoice values effectuated by early payments which are applied to reduce a Participant's Peak Market Activity

as contemplated by other terms of the Credit Policy; provided that the initial Peak Market Activity shall not be less than the average value calculated using the weeks for which no early payment was made.

A Participant may reduce its Financial Security Requirement by agreeing in writing (in a form acceptable to PJMSettlement) to make additional payments, including prepayments, as and when necessary to ensure that such Participant's Total Net Obligation at no time exceeds such reduced Financial Security Requirement.

PJMSettlement may, at its discretion, adjust a Participant's Financial Security Requirement if PJMSettlement determines that the Peak Market Activity is not representative of such Participant's expected activity, as a consequence of known, measurable, and sustained changes. Such changes may include the loss (without replacement) of short-term load contracts, when such contracts had terms of three months or more and were acquired through state-sponsored retail load programs, but shall not include short-term buying and selling activities.

PJMSettlement may waive the Financial Security Requirement for a Participant that agrees in writing that it shall not, after the date of such agreement, incur obligations under any of the Agreements. Such entity's access to all electronic transaction systems administered by PJM shall be terminated.

PJMSettlement will maintain a posting of each Participant's Financial Security Requirement on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

E. Working Credit Limit

PJMSettlement will establish a Working Credit Limit for each Participant against which its **Total Net Obligation** will be monitored. The Working Credit Limit is defined as 75% of the Financial Security provided to PJMSettlement and/or 75% of the Unsecured Credit Allowance determined by PJMSettlement based on a credit evaluation, as reduced by any applicable credit requirement determinants defined in this policy. A Participant's Total Net Obligation should not exceed its Working Credit Limit.

> Example: After a credit evaluation by PJMSettlement, a Participant is deemed able to support an Unsecured Credit Allowance of $10.0 million. The Participant will be assigned a Working Credit Limit of $8.5 million. PJMSettlement will monitor the Participant's Total Net Obligations against the Working Credit Limit.

A Participant with an Unsecured Credit Allowance may choose to provide Financial Security in order to increase its Working Credit Limit. A Participant with no Unsecured Credit Allowance may also choose to increase its Working Credit Limit by providing Financial Security in an amount greater than its Peak Market Activity.

If a Participant's Total Net Obligation approaches its Working Credit Limit, PJMSettlement may require the Participant to make an advance payment or increase its Financial Security in order to maintain its Total Net Obligation below its Working Credit Limit. Except as explicitly provided

below, advance payments shall not serve to reduce the Participant's Peak Market Activity for the purpose of calculating credit requirements.

> Example: After 10 days, and with 5 days remaining before the bill is due to be paid, a Participant approaches its $4.0 million Working Credit Limit. PJMSettlement may require a prepayment of $2.0 million in order that the Total Net Obligation will not exceed the Working Credit Limit.

If a Participant exceeds its Working Credit Limit or is required to make advance payments more than ten times during a 52-week period, PJMSettlement may require Financial Security in an amount as may be deemed reasonably necessary to support its Total Net Obligation.

A Participant receiving unsecured credit may make early payments up to ten times in a rolling 52-week period in order to reduce its Peak Market Activity for credit requirement purposes. Imputed Peak Market Activity reductions for credit purposes will be applied to the billing period for which the payment was received. Payments used as the basis for such reductions must be received prior to issuance or posting of the invoice for the relevant billing period. The imputed Peak Market Activity reduction attributed to any payment may not exceed the amount of Unsecured Credit for which the Participant is eligible.

F. Credit Limit Setting For Affiliates

If two or more Participants are Affiliates and each is being granted an Unsecured Credit Allowance and a corresponding Working Credit Limit, PJMSettlement will consider the overall creditworthiness of the Affiliated Participants when determining the Unsecured Credit Allowances and Working Credit Limits in order not to grant more Unsecured Credit than the overall corporation could support.

> **Example:** Participants A and B each have a $10.0 million Corporate Guaranty from their common parent, a holding company with an Unsecured Credit Allowance calculation of $12.0 million. PJMSettlement may limit the Unsecured Credit Allowance for each Participant to $6.0 million, so the total Unsecured Credit Allowance does not exceed the corporate total of $12.0 million.

PJMSettlement will work with Affiliated Participants to allocate the total Unsecured Credit Allowance among the Affiliates while assuring that no individual Participant, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. The aggregate Unsecured Credit for a Participant, including Unsecured Credit Allowance granted based on its own creditworthiness and any Unsecured Credit Allowance conveyed through a Guaranty shall not exceed $50 million. The aggregate Unsecured Credit for a group of Affiliates shall not exceed $50 million. A group of Affiliates subject to this cap shall request PJMSettlement to allocate the maximum Unsecured Credit and Working Credit Limit amongst the group, assuring that no individual Participant or common guarantor, shall exceed the Unsecured Credit level appropriate for its credit strength and activity.

G. Working Credit Limit Violations

1) Notification

A Participant is subject to notification when its Total Net Obligation to PJMSettlement approaches the Participant's established Working Credit Limit.

2) Suspension

A Participant that exceeds its Working Credit Limit is subject to suspension from participation in the PJM markets and from scheduling any future Transmission Service unless and until Participant's credit standing is brought within acceptable limits. A Participant will have two Business Days from notification to remedy the situation in a manner deemed acceptable by PJMSettlement. Additionally, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant's ongoing Transmission Service and participation in PJM Markets. Failure to comply with this policy will be considered an event of default under this credit policy.

H. PJM Administrative Charges

Financial Security held by PJMSettlement shall also secure obligations to PJM for PJM administrative charges.

I. Pre-existing Financial Security

PJMSettlement's credit requirements are applicable as of the effective date of the filing on May 5, 2010 by PJM and PJMSettlement of amendments to Attachment Q. Financial Security held by PJM prior to the effective date of such amendments shall be held by PJM for the benefit of PJMSettlement.

III. VIRTUAL TRANSACTION SCREENING

A. Credit and Financial Security

PJMSettlement does not require a Market Participant to establish separate or additional credit for submitting Virtual Transactions. If a Market Participant chooses to establish additional Financial Security and/or Unsecured Credit Allowance in order to increase its Credit Available for Virtual Transactions, the Market Participant's Working Credit Limit for Virtual Transactions shall be increased in accordance with the definition therof. The Financial Security and/or Unsecured Credit Allowance available to increase a Market Participant's Credit Available for Virtual Transactions shall be the amount of Financial Security and/or Unsecured Credit Allowance available after subtracting any credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy, as applicable.

If a Market Participant chooses to provide additional Financial Security in order to increase its **Credit Available for Virtual Transactions PJMSettlement** may establish a reasonable timeframe, not to exceed three months, for which such Financial Security must be maintained. PJMSettlement will not impose such restriction on a deposit unless a Market Participant is

notified prior to making the deposit. Such restriction, if applied, shall be applied to all future deposits by all Market Participants engaging in Virtual Transactions.

A Market Participant wishing to increase its Credit Available for Virtual Transactions by providing additional Financial Security may make the appropriate arrangements with PJMSettlement. PJMSettlement will make a good faith effort to make new Financial Security available as Credit Available for Virtual Transactions as soon as practicable after confirmation of receipt. In any event, however, Financial Security received and confirmed by noon on a business day will be applied (as provided under this policy) to Credit Available for Virtual Transactions no later than 10:00 am on the following business day. Receipt and acceptance of wired funds for cash deposit shall mean actual receipt by PJMSettlement's bank, deposit into PJMSettlement's customer deposit account, and confirmation by PJMSettlement that such wire has been received and deposited. Receipt and acceptance of letters of credit shall mean receipt of the original letter of credit or amendment thereto, and confirmation from PJMSettlement's credit and legal staffs that such letter of credit or amendment thereto conforms to PJMSettlement's requirements, which confirmation shall be made in a reasonable and practicable timeframe. To facilitate this process, bidders wiring funds for the purpose of increasing their Credit Available for Virtual Transactions are advised to specifically notify PJMSettlement that a wire is being sent for such purpose.

B. Virtual Transaction Screening Process

All Virtual Transactions submitted to PJM shall be subject to a credit screen prior to acceptance in the Day-ahead Energy Market auction. The credit screen process will automatically reject Virtual Transactions submitted by the PJM market participant if the participant's Credit Available for Virtual Transactions is exceeded by the **Virtual Credit Exposure** that is calculated based on the participant's submitted Virtual Transactions as described below.

A Participant's Virtual Credit Exposure will be calculated on a daily basis for all Virtual Transactions submitted by the market participant for the next market day using the following equation:

Virtual Credit Exposure = INC and DEC Exposure + Up-to Congestion Exposure
Where:

1) INC and DEC Exposure is calculated as:

(a) ((the total MWh bid or offered, whichever is greater, hourly at each node) x the Nodal Reference Price x 1 day) summed over all nodes and all hours; plus (b) ((the difference between the total bid MWh cleared and total offered MWh cleared hourly at each node) x Nodal Reference Price) summed over all nodes and all hours for the previous cleared Day-ahead Energy Market.

2) Up-to Congestion Exposure is calculated as:

(a) Total MWh bid hourly for each Up-to Congestion Transaction x (price bid – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours; plus (b) Total MWh cleared hourly for each Up-to Congestion Transaction x (cleared price – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours for the previous cleared Day-ahead Energy Market, provided that hours for which the calculation for an Up-to Congestion Transaction is negative, it shall be deemed to have a zero contribution to the sum.

If a Market Participant's Virtual Transactions are rejected as a result of the credit screen process, the Market Participant will be notified via an eMKT error message. A Market Participant whose Virtual Transactions are rejected may alter its Virtual Transactions so that its Virtual Credit Exposure does not exceed its Credit Available forVirtual Transactions, and may resubmit them. Virtual Transactions may be submitted in one or more groups during a day. If one or more groups of Virtual Transactions is submitted and accepted, and a subsequent group of submitted Virtual Transactions causes the total submitted Virtual Transactions to exceed the Virtual Credit Exposure, then only that subsequent set of Virtual Transactions will be rejected. Previously accepted Virtual Transactions will not be affected, though the Market Participant may choose to withdraw them voluntarily.

IV. RELIABILITY PRICING MODEL AUCTION AND PRICE RESPONSIVE DEMAND CREDIT REQUIREMENTS

Settlement during any Delivery Year of cleared positions resulting or expected to result from any Reliability Pricing Model Auction shall be included as appropriate in Peak Market Activity, and the provisions of this Attachment Q shall apply to any such activity and obligations arising therefrom. In addition, the provisions of this section shall apply to any entity seeking to participate in any RPM Auction, to address credit risks unique to such auctions. The provisions of this section also shall apply under certain circumstances to PRD Providers that seek to commit Price Responsive Demand pursuant to the provisions of the Reliability Assurance Agreement.

A. Applicability

A Market Seller seeking to submit a Sell Offer in any Reliability Pricing Model Auction based on any Capacity Resource for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before submitting such Sell Offer. A PRD Provider seeking to commit Price Responsive Demand for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before it may commit the Price Responsive Demand. Credit must be maintained until such risk of non-performance is substantially eliminated, but may be reduced commensurate with the reduction in such risk, as set forth in Section IV.C.

For purposes of this provision, a resource for which there is a materially increased risk of non-performance shall mean: (i) a Planned Generation Capacity Resource; (ii) a Planned Demand Resource or an Energy Efficiency Resource; (iii) a Qualifying Transmission Upgrade; (iv) an existing or Planned Generation Capacity Resource located outside the PJM Region that at the time it is submitted in a Sell Offer has not secured firm transmission service to the border of the

PJM Region sufficient to satisfy the deliverability requirements of the Reliability Assurance Agreement; or (v) Price Responsive Demand to the extent the responsible PRD Provider has not registered PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

B. Reliability Pricing Model Auction and Price Responsive Demand Credit Requirement

Except as provided for Credit-Limited Offers below, for any resource specified in Section IV.A, other than Price Responsive Demand, the credit requirement shall be the RPM Auction Credit Rate, as provided in Section IV.D, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction. For Qualified Transmission Upgrades, the credit requirements shall be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit. The RPM Auction Credit Requirement for each Market Seller shall be the sum of the credit requirements for all such resources to be offered by such Market Seller in the auction or, as applicable, cleared by such Market Seller from the relevant auctions. For Price Responsive Demand specified in section IV.A, the credit requirement shall be based on the Nominal PRD Value (stated in Unforced Capacity terms) times the Price Responsive Demand Credit Rate as set forth in section IV.E.

Except for Credit-Limited Offers, the RPM Auction Credit Requirement for a Market Seller will be reduced for any Delivery Year to the extent less than all of such Market Seller's offers clear in the Base Residual Auction or any Incremental Auction for such Delivery Year. Such reduction shall be proportional to the quantity, in megawatts, that failed to clear in such Delivery Year.

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Seller electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement, in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the Auction Credit Rate resulting from section IV.D.b.; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Seller electing this alternative, the RPM Auction Credit Requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-Limited Offer, and the RPM Auction Credit Requirement subsequent to posting of the results will be the Auction Credit Rate, as provided in Section IV.D.b, c. or d., as applicable, times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The availability and operational details of Credit-Limited Offers shall be as described in the PJM Manuals.

As set forth in Section IV.D, a Market Seller's Auction Credit Requirement shall be determined separately for each Delivery Year.

C. Reduction in Credit Requirement

As specified in Section IV.D, the RPM Auction Credit Rate may be reduced under certain circumstances after the auction has closed.

The Price Responsive Demand credit requirement shall be reduced as and to the extent the PRD Provider registers PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

In addition, the RPM Auction Credit Requirement for a Participant for any given Delivery Year shall be reduced periodically, provided the Participant successfully meets progress milestones that reduce the risk of non-performance, as follows:

a. For Planned Demand Resources and Energy Efficiency Resources, the RPM Auction Credit Requirement will be reduced in direct proportion to the megawatts of such Demand Resource that the Resource Provider qualifies as a Capacity Resource, in accordance with the procedures established under the Reliability Assurance Agreement.

b. For Existing Generation Capacity Resources located outside the PJM Region that have not secured sufficient firm transmission to the border of the PJM Region prior to the auction in which such resource is first offered, the RPM Credit Requirement shall be reduced in direct proportion to the megawatts of firm transmission service secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

c. For Planned Generation Capacity Resources, the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B beginning as of the effective date of an Interconnection Service Agreement, and shall be reduced to zero on the date of commencement of Interconnection Service.

d. For Planned Generation Capacity Resources located outside the PJM Region, the RPM Credit Requirement shall be reduced by 50% once the conditions in both b and c above are met, i.e., the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B when 1) ~~beginning as of~~ the ~~effective date of the~~ equivalent of an Interconnection Service Agreement becomes effective, and 2) ~~when~~ 50% or more megawatts of firm transmission service have been secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement. The RPM Credit Requirement for a Planned Generation Capacity Resource located outside the PJM Region shall be reduced to zero when 1) the resource commences Interconnection Service and 2) 100% of the megawatts of firm transmission service have been secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

e. For Qualifying Transmission Upgrades, the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B beginning as of the effective date of the latest associated Interconnection Service Agreement (or, when a project will have no such agreement, an Upgrade Construction Service Agreement), and shall be reduced to zero on the date the

Qualifying Transmission Upgrade is placed in service. In addition, a Qualifying Transmission Upgrade will be allowed a reduction in its RPM Credit Requirement equal to the amount of collateral currently posted with PJM for the facility construction when the Qualifying Transmission Upgrade meets the following requirements: the Upgrade Construction Service Agreement has been fully executed, the full estimated cost to complete as most recently determined or updated by PJM has been fully paid or collateralized, and all regulatory and other required approvals (except those that must await construction completion) have been obtained. Such reduction in RPM Credit Requirement may not be transferred across different projects.

D. RPM Auction Credit Rate

As set forth in the PJM Manuals, a separate Auction Credit Rate shall be calculated for each Delivery ~~y~~Year prior to each Reliability Pricing Model Auction for such Delivery Year, as follows:

~~For Delivery Years through the Delivery Year that ends on May 31, 2012, the Auction Credit Rate for any resource for a Delivery Year shall be (the greater of $20/MW-day or 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year.~~

~~For Delivery Years beginning with the Delivery Year that commences on June 1, 2012:~~

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the greater of ((A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year.

b. Subsequent to the posting of the results from a Base Residual Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A~~i~~) $20/MW-day or (B~~ii~~) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).

c. For any resource not previously committed for a Delivery Year that seeks to participate in an Incremental Auction, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A~~i~~) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B~~ii~~) 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located or (C~~iii~~) $20 per MW-day) times the number of days in such Delivery Year; and~~.~~

(ii) For Capacity Performance Resources, the (greater of (A) 0.5 times Net Cost of New Entry or (B) $20/MW-day) times the number of days in such Delivery Year.

d. Subsequent to the posting of the results of an Incremental Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For Base Capacity Resources: (the greater of (A~~i~~) $20/MW-day or (B~~ii~~) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year, but no greater than the Auction Credit Rate previously established for such resource's participation in such Incremental Auction pursuant to subsection (c) above) times the number of days in such Delivery Year~~.~~; and

(ii) For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).

E. Price Responsive Demand Credit Rate

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (ii) $20 per MW-day) times the number of days in such Delivery Year;

b. Subsequent to the posting of the results from a Base Residual Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for Price Responsive Demand registered prior to such auction shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the PRD load is located) times the number of days in such Delivery Year times a final price uncertainty factor of 1.05;

c. For any additional Price Responsive Demand that seeks to commit in a Third Incremental Auction in response to a qualifying change in the final LDA load forecast, the Price Responsive Demand Credit Rate shall be the same as the rate for Price Responsive Demand that had cleared in the Base Residual Auction;

d. Subsequent to the posting of the results of the Third Incremental Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for all Price Responsive Demand, shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Final Zonal Capacity Price for the Locational Deliverability Area within which the Price Responsive Demand is located) times the number of days in such Delivery Year, but no greater than the Price Responsive Demand Credit Rate previously established under subsections (a), (b), or (c) of this section for such Delivery Year.

F. RPM Seller Credit - Additional Form of Unsecured Credit for RPM

In addition to the forms of credit specified elsewhere in this Attachment Q, RPM Seller Credit shall be available to Market Sellers, but solely for purposes of satisfying RPM Auction Credit Requirements. If a supplier has a history of being a net seller into PJM markets, on average, over the past 12 months, then PJMSettlement will count as available Unsecured Credit twice the average of that participant's total net monthly PJMSettlement bills over the past 12 months. This RPM Seller Credit shall be subject to the cap on available Unsecured Credit as established in Section II.F.

G. Credit Responsibility for Traded Planned RPM Capacity Resources

PJMSettlement may require that credit and financial responsibility for planned RPM Capacity Resources that are traded remain with the original party (which for these purposes, means the party bearing credit responsibility for the planned RPM Capacity Resource immediately prior to trade) unless the receiving party independently establishes consistent with the PJM credit policy, that it has sufficient credit with PJMSettlement and agrees by providing written notice to PJMSettlement that it will fully assume the credit responsibility associated with the traded planned RPM Capacity Resource.

V. FINANCIAL TRANSMISSION RIGHT AUCTIONS

A. FTR Credit Limit.

PJMSettlement will establish an FTR Credit Limit for each Participant. Participants must maintain their FTR Credit Limit at a level equal to or greater than their FTR Credit Requirement. FTR Credit Limits will be established only by a Participant providing Financial Security.

B. FTR Credit Requirement.

For each Participant with FTR activity, PJMSettlement shall calculate an FTR Credit Requirement based on FTR cost less a discounted historical value. FTR Credit Requirements shall be further adjusted by ARR credits available and by an amount based on portfolio diversification, if applicable. The requirement will be based on individual monthly exposures which are then used to derive a total requirement.

The FTR Credit Requirement shall be calculated by first adding for each month the FTR Monthly Credit Requirement Contribution for each submitted, accepted, and cleared FTR and then subtracting the prorated value of any ARRs held by the Participant for that month. The resulting twelve monthly subtotals represent the expected value of net payments between PJMSettlement and the Participant for FTR activity each month during the Planning Period. Subject to later adjustment by an amount based on portfolio diversification, if applicable, the FTR Credit Requirement shall be the sum of the individual positive monthly subtotals, representing months in which net payments to PJMSettlement are expected.

C. Rejection of FTR Bids.

Bids submitted into an auction will be rejected if the Participant's FTR Credit Requirement including such submitted bids would exceed the Participant's FTR Credit Limit, or if the Participant fails to establish additional credit as required pursuant to provisions related to portfolio diversification.

D. FTR Credit Collateral Returns.

A Market Participant may request from PJMSettlement the return of any collateral no longer required for the FTR auctions. PJMSettlement is permitted to limit the frequency of such requested collateral returns, provided that collateral returns shall be made by PJMSettlement at least once per calendar quarter, if requested by a Market Participant.

E. Credit Responsibility for Traded FTRs.

PJMSettlement may require that credit responsibility associated with an FTR traded within PJM's eFTR system remain with the original party (which for these purposes, means the party bearing credit responsibility for the FTR immediately prior to trade) unless and until the receiving party independently establishes, consistent with the PJM credit policy, sufficient credit with PJMSettlement and agrees through confirmation of the FTR trade within the eFTR system that it will meet in full the credit requirements associated with the traded FTR.

F. Portfolio Diversification.

Subsequent to calculating a tentative cleared solution for an FTR auction (or auction round), PJM shall both:

1. Determine the FTR Portfolio Auction Value, including the tentative cleared solution. Any Participants with such FTR Portfolio Auction Values that are negative shall be deemed FTR Flow Undiversified.

2. Measure the geographic concentration of the FTR Flow Undiversified portfolios by testing such portfolios using a simulation model including, one at a time, each planned transmission outage or other network change which would substantially affect the network for the specific auction period. A list of such planned outages or changes anticipated to be modeled shall be posted prior to commencement of the auction (or auction round). Any FTR Flow Undiversified portfolio that experiences a net reduction in calculated congestion credits as a result of any one or more of such modeled outages or changes shall be deemed FTR Geographically Undiversified.

For portfolios that are FTR Flow Undiversified but not FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to twice the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For Participants with portfolios that are both FTR Flow Undiversified and FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to three times the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For portfolios that are FTR Flow Undiversified in months subsequent to the current planning year, these incremental amounts, calculated on a monthly basis, shall be reduced (but not below zero) by an amount up to 25% of the monthly value of ARR credits that are held by a Participant. Subsequent to the ARR allocation process preceding an annual FTR auction, such ARRs credits shall be reduced to zero for months associated with that ARR allocation process. PJMSettlement may recalculate such ARR credits at any time, but at a minimum shall do so subsequent to each annual FTR auction. If a reduction in such ARR credits at any time increases the amount of credit required for the Participant beyond its credit available for FTR activity, the Participant must increase its credit to eliminate the shortfall.

If the FTR Credit Requirement for any Participant exceeds its credit available for FTRs as a result of these diversification requirements for the tentatively cleared portfolio of FTRs, PJMSettlement shall immediately issue a demand for additional credit, and such demand must be fulfilled before 4:00 p.m. on the business day following the demand. If any Participant does not timely satisfy such demand, PJMSettlement, in coordination with PJM, shall cause the removal that Participant's entire set of bids for that FTR auction (or auction round) and a new cleared solution shall be calculated for the entire auction (or auction round).

If necessary, PJM shall repeat the auction clearing calculation. PJM shall repeat these portfolio diversification calculations subsequent to any such secondary clearing calculation, and PJMSettlement shall require affected Participants to establish additional credit.

G. FTR Administrative Charge Credit Requirement

In addition to any other credit requirements, PJMSettlement may apply a credit requirement to cover the maximum administrative fees that may be charged to a Participant for its bids and offers.

H. Long-Term FTR Credit Recalculation

Long-term FTR Credit Requirement calculations shall be updated annually for known history, consistent with updating of historical values used for FTR Credit Requirement calculations in the annual auctions.

VI. EXPORT TRANSACTION SCREENING

Export Transactions in the Real-time Energy Market shall be subject to Export Transaction Screening. Export Transaction Screening may be performed either for the duration of the entire Export Transaction, or separately for each time interval comprising an Export Transaction. PJM will deny or curtail all or a portion (based on the relevant time interval) of an Export Transaction if that Export Transaction, or portion thereof, would otherwise cause the Market Participant's Export Credit Exposure to exceed its Credit Available for Export Transactions. Export Transaction Screening shall be applied separately for each Operating Day and shall also be applied to each Export Transaction one or more times prior to the market clearing process for each relevant time interval. Export Transaction Screening shall not apply to transactions established directly by and between PJM and a neighboring Balancing Authority for the purpose of maintaining reliability.

A Market Participant's credit exposure for an individual Export Transaction shall be the MWh volume of the Export Transaction for each relevant time interval multiplied by each relevant Export Transaction Price Factor and summed over all relevant time intervals of the Export Transaction.

VII. FORMS OF FINANCIAL SECURITY

Participants that provide Financial Security must provide the security in a PJMSettlement approved form and amount according to the guidelines below.

Financial Security which is no longer required to be maintained under provisions of the Agreements shall be returned at the request of a participant no later than two Business Days following determination by PJMSettlement within a commercially reasonable period of time that such collateral is not required.

Except when an event of default has occurred, a Participant may substitute an approved PJMSettlement form of Financial Security for another PJMSettlement approved form of Financial Security of equal value. The Participant must provide three (3) Business Days notice to PJMSettlement of its intent to substitute the Financial Security. PJMSettlement will release the replaced Financial Security with interest, if applicable, within (3) Business Days of receiving an approved form of substitute Financial Security.

A. Cash Deposit

Cash provided by a Participant as Financial Security will be held in a depository account by PJMSettlement with interest earned at PJMSettlement's overnight bank rate, and accrued to the Participant. PJMSettlement also may establish an array of investment options among which a Participant may choose to invest its cash deposited as Financial Security. Such investment options shall be comprised of high quality debt instruments, as determined by PJMSettlement, and may include obligations issued by the federal government and/or federal government sponsored enterprises. These investment options will reside in accounts held in PJMSettlement's name in a banking or financial institution acceptable to PJMSettlement. Where practicable, PJMSettlement may establish a means for the Participant to communicate directly with the bank or financial institution to permit the Participant to direct certain activity in the PJMSettlement account in which its Financial Security is held. PJMSettlement will establish and publish procedural rules, identifying the investment options and respective discounts in collateral value that will be taken to reflect any liquidation, market and/or credit risk presented by such investments. PJMSettlement has the right to liquidate all or a portion of the account balances at its discretion to satisfy a Participant's Total Net Obligation to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

B. Letter Of Credit

An unconditional, irrevocable standby letter of credit can be utilized to meet the Financial Security requirement. As stated below, the form, substance, and provider of the letter of credit must all be acceptable to PJMSettlement.

- The letter of credit will only be accepted from U.S.-based financial institutions or U.S. branches of foreign financial institutions ("financial institutions") that have a minimum corporate debt rating of "A" by Standard & Poor's or Fitch Ratings, or "A2" from Moody's Investors Service, or an equivalent short term rating from one of these agencies. PJMSettlement will consider the lowest applicable rating to be the rating of the financial institution. If the rating of a financial institution providing a letter of credit is lowered below A/A2 by any rating agency, then PJMSettlement may require the Participant to provide a letter of credit from another financial institution that is rated A/A2 or better, or to provide a cash deposit. If a letter of credit is provided from a U.S. branch of a foreign institution, the U.S. branch must itself comply with the terms of this credit policy, including having its own acceptable credit rating.

- The letter of credit shall state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety (90) days prior written notice from the issuing financial institution. If PJM or PJMSettlement receives notice from the issuing financial institution that the current letter of credit is being cancelled, the Participant will be required to provide evidence, acceptable to PJMSettlement, that such letter of credit will be replaced with appropriate Financial Security, effective as of the cancellation date of the letter of credit, no later than thirty (30) days before the cancellation date of the letter of credit, and no later than ninety (90) days after the notice of cancellation. Failure to do so will constitute a default under this credit policy and one of more of the Agreements.

- The letter of credit must clearly state the full names of the "Issuer", "Account Party" and "Beneficiary" (PJMSettlement), the dollar amount available for drawings, and shall specify that funds will be disbursed upon presentation of the drawing certificate in accordance with the instructions stated in the letter of credit. The letter of credit should specify any statement that is required to be on the drawing certificate, and any other terms and conditions that apply to such drawings.

- The PJMSettlement Credit Application contains an acceptable form of a letter of credit that should be utilized by a Participant choosing to meet its Financial Security requirement with a letter of credit. If the letter of credit varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a letter of credit and meeting the policy provisions are the responsibility of the Participant

- PJMSettlement may accept a letter of credit from a Financial Institution that does not meet the credit standards of this policy provided that the letter of credit has third-party support, in a form acceptable to PJMSettlement, from a financial institution that does meet the credit standards of this policy.

VIII. POLICY BREACH AND EVENTS OF DEFAULT

A Participant will have two Business Days from notification of Breach (including late payment notice) or notification of a Collateral Call to remedy the Breach or satisfy the Collateral Call in a manner deemed acceptable by PJMSettlement. Failure to remedy the Breach or satisfy such Collateral Call within such two Business Days will be considered an event of default. If a Participant fails to meet the requirements of this policy but then remedies the Breach or satisfies a Collateral Call within the two Business Day cure period, then the Participant shall be deemed to have complied with the policy. Any such two Business Day cure period will expire at 4:00 p.m. eastern prevailing time on the final day.

Only one cure period shall apply to a single event giving rise to a breach or default. Application of Financial Security towards a non-payment Breach shall not be considered a satisfactory cure of the Breach if the Participant fails to meet all requirements of this policy after such application.

Failure to comply with this policy (except for the responsibility of a Participant to notify PJMSettlement of a Material change) shall be considered an event of default. Pursuant to § 15.1.3(a) of the Operating Agreement of PJM Interconnection, L.L.C. and § I.7.3 of the PJM Open Access Transmission Tariff, non-compliance with the PJMSettlement credit policy is an event of default under those respective Agreements. In event of default under this credit policy or one or more of the Agreements, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant’s ongoing Transmission Service and participation in PJM Markets. PJMSettlement has the right to liquidate all or a portion of a Participant’s Financial Security at its discretion to satisfy Total Net Obligations to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

PJMSettlement may hold a defaulting Participant’s Financial Security for as long as such party’s positions exist and consistent with the PJM credit policy in this Attachment Q, in order to protect PJM’s membership from default.

No payments shall be due to a Participant, nor shall any payments be made to a Participant, while the Participant is in default or has been declared in Breach of this policy or the Agreements, or while a Collateral Call is outstanding. PJMSettlement may apply towards an ongoing default any amounts that are held or later become available or due to the defaulting Participant through PJM's markets and systems.

In order to cover Obligations, PJMSettlement may hold a Participant's Financial Security through the end of the billing period which includes the 90th day following the last day a Participant had activity, open positions, or accruing obligations (other than reconciliations and true-ups), and until such Participant has satisfactorily paid any obligations invoiced through such period. Obligations incurred or accrued through such period shall survive any withdrawal from PJM. In event of non-payment, PJMSettlement may apply such Financial Security to such Participant's Obligations, even if Participant had previously announced and effected its withdrawal from PJM.

IX. DEFINITIONS:

All capitalized terms in this Attachment Q that are not otherwise defined herein shall have the same meaning as they are defined in the Agreements.

Affiliate
Affiliate is defined in the PJM Operating Agreement, §1.2.

Agreements
Agreements are the Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, the Reliability Assurance Agreement – West, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Applicant
Applicant is an entity desiring to become a PJM Member, or to take Transmission Service that has submitted the PJMSettlement Credit Application, PJMSettlement Credit Agreement and other required submittals as set forth in this policy.

Breach
Breach is the status of a Participant that does not currently meet the requirements of this policy or other provisions of the Agreements.

Business Day
A Business Day is a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Canadian Guaranty
Canadian Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of this credit policy.

Capacity
Capacity is the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Collateral Call
Collateral Call is a notice to a Participant that additional Financial Security, or possibly early payment, is required in order to remain in, or to regain, compliance with this policy.

Corporate Guaranty
Corporate Guaranty is a legal document used by one entity to guaranty the obligations of another entity.

Credit Available for Export Transactions
Credit Available for Export Transactions is a set-aside of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions
A Market Participant’s Credit Available for Virtual Transactions is the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy.

Credit-Limited Offer
Credit-Limited Offer shall mean a Sell Offer that is submitted by a Market Seller in an RPM Auction subject to a maximum credit requirement specified by such Market Seller.

Credit Score
Credit Score is a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

Export Credit Exposure
Export Credit Exposure is determined for each Market Participant for a given Operating Day, and is the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price

The Export Nodal Reference Price at each location is the 97th percentile real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction
An Export Transaction is a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transactions Net Activity
Export Transactions Net Activity shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Export Transaction Price Factor
The Export Transaction Price Factor for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening
Export Transaction Screening is the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Financial Security
Financial Security is a cash deposit or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Foreign Guaranty
Foreign Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of this credit policy.

FTR Credit Limit
FTR Credit Limit will be equal to the amount of credit established with PJMSettlement that a Participant has specifically designated to PJMSettlement to be set aside and used for FTR

activity. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the Participant may have with PJMSettlement.

FTR Credit Requirement
FTR Credit Requirement is the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or is bidding for. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems.

FTR Flow Undiversified
FTR Flow Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Geographically Undiversified
FTR Geographically Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Historical Value
FTR Historical Value – For each FTR for each month, this is the historical weighted average value over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year. FTR Historical Values shall be calculated separately for on-peak, off-peak, and 24-hour FTRs for each month of the year. FTR Historical Values shall be adjusted by plus or minus ten percent (10%) for cleared counterflow or normal flow FTRs, respectively, in order to mitigate exposure due to uncertainty and fluctuations in actual FTR value.

FTR Monthly Credit Requirement Contribution
FTR Monthly Credit Requirement Contribution - For each FTR for each month, this is the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity
FTR Net Activity shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant
FTR Participant shall mean any Market Participant that is required to provide Financial Security in order to participate in PJM's FTR auctions.

FTR Portfolio Auction Value
FTR Portfolio Auction Value shall mean for each Participant (or Participant account), the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Market Participant
Market Participant shall have the meaning provided in the Operating Agreement.

Material
For these purposes, material is defined in §I.B.3, Material Changes. For the purposes herein, the use of the term "material" is not necessarily synonymous with use of the term by governmental agencies and regulatory bodies.

Member
Member shall have the meaning provided in the Operating Agreement.

Minimum Participation Requirements
A set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM markets, as set forth herein and in the Form of Annual Certification set forth as Appendix 1 to this Attachment Q. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Appendix 1 to this Attachment Q.

Net Obligation
Net Obligation is the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position
Net Sell Position is the amount of Net Obligation when Net Obligation is negative.

Nodal Reference Price
The Nodal Reference Price at each location is the 97th percentile price differential between hourly day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. In order to capture seasonality effects and maintain a two-month reference period, reference months will be grouped by two, starting with January (e.g., Jan-Feb, Mar-Apr, … , Jul-Aug, … Nov-Dec). For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

Obligation
Obligation is all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for Capacity purchases within the PJM Capacity markets will be

added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Operating Agreement of PJM Interconnection, L.L.C., ("Operating Agreement")
The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of June 2, 1997, on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Participant
A Participant is a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer.

Peak Market Activity
Peak Market Activity is a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of section II.D of this Credit Policy.

PJM Markets
The PJM Markets are the PJM Interchange Energy Market and the PJM Capacity markets as established by the Operating Agreement. Also any other markets that exist or may be established in the future wherein Participants may incur Obligations to PJMSettlement.

PJM Open Access Transmission Tariff ("O.A.T.T.")
The Open Access Transmission Tariff of PJM Interconnection, L.L.C., on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Reliability Assurance Agreement ("R.A.A.")
See the definition of the Reliability Assurance Agreement ("R.A.A.") in the Operating Agreement.

RPM Seller Credit
RPM Seller Credit is an additional form of Unsecured Credit defined in section IV of this document.

Seller Credit
A Seller Credit is a form of Unsecured Credit extended to Participants that have a consistent long-term history of selling into PJM Markets, as defined in this document.

Tangible Net Worth
Tangible Net Worth is all assets (not including any intangible assets such as goodwill) less all liabilities. Any such calculation may be reduced by PJMSettlement upon review of the available financial information.

Total Net Obligation

Total Net Obligation is all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position
Total Net Sell Position is all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Transmission Customer
Transmission Customer is a Transmission Customer is an entity taking service under Part II or Part III of the O.A.T.T.

Transmission Service
Transmission Service is any or all of the transmission services provided by PJM pursuant to Part II or Part III of the O.A.T.T.

Uncleared Bid Exposure
Uncleared Bid Exposure is a measure of exposure from Increment Offers and Decrement Bids activity relative to a Participant's established credit as defined in this policy. It is used only as a pre-screen to determine whether a Participant's Increment Offers and Decrement Bids should be subject to Increment Offer and Decrement Bid Screening.

Unsecured Credit
Unsecured Credit is any credit granted by PJMSettlement to a Participant that is not secured by a form of Financial Security.

Unsecured Credit Allowance
Unsecured Credit Allowance is Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Financial Security. See also: "Working Credit Limit."

Up-to Congestion Counterflow Transaction
An Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month
An Up-to Congestion Historical Month is a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction
An Up-to Congestion Transaction will be deemed an Up-to Congestion Prevailing Flow Transaction if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price
The Up-to Congestion Reference Price for an Up-to Congestion Transaction is the specified percentile price differential between source and sink (defined as sink price minus source price) for hourly real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30^{th} percentile
For Up-to Congestion Counterflow Transactions when bid: 20^{th} percentile
For Up-to Congestion Counterflow Transactions when cleared: 5^{th} percentile

Virtual Credit Exposure
Virtual Credit Exposure is the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in this policy.

Virtual Transaction Screening
Virtual Transaction Screening is the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity
Virtual Transactions Net Activity shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Virtual Transactions Net Activity may be positive or negative.

Working Credit Limit
Working Credit Limit amount is 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement. The Working Credit Limit establishes the maximum amount of Total Net Obligation that a Market Participant may have outstanding at any time. The calculation of Working Credit Limit shall take into account applicable reductions for Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Working Credit Limit for Virtual Transactions
The Working Credit Limit for Virtual Transactions shall be calculated as 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement when the Market Participant is at or below its Peak Market Activity credit requirements as specified in section II.D of this Credit Policy. When the Market Participant provides additional Unsecured Credit Allowance and/or Financial Security in excess of its Peak Market Activity credit requirements, such additional Unsecured Credit Allowance and/or Financial Security shall not be discounted by 25% when calculating the Working Credit Limit for Virtual Transactions. The Working Credit Limit for Virtual Transactions is a component in the calculation of Credit Available for Virtual Transactions. The calculation of Working Credit Limit for Virtual Transactions shall take into account applicable reductions for

Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Appendix 1 to Attachment Q

PJM MINIMUM PARTICIPATION CRITERIA
OFFICER CERTIFICATION FORM

Participant Name: ____ ("Participant")

I, ____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. and PJM Settlement, Inc. (”PJMSettlement”) are relying on this certification as evidence that Participant meets the minimum requirements set forth in Attachment Q to the PJM Open Access Transmission Tariff ("PJM Tariff"), hereby certify that I have full authority to represent on behalf of Participant and further represent as follows, as evidenced by my initialing each representation in the space provided below:

1. All employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Amended and Restated Operating Agreement (“PJM Operating Agreement”) on behalf of the Participant have received appropriate[1] training and are authorized to transact on behalf of Participant.__________

2. Participant has written risk management policies, procedures, and controls, approved by Participant’s independent risk management function[2] and applicable to transactions in the PJM markets in which it participates and for which employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Operating Agreement have been trained, that provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Participant is exposed, including, but not limited to credit risks, liquidity risks and market risks.___________

3. An FTR Participant (as defined in Attachment Q to the PJM Tariff) must make either the following 3.a. or 3.b. additional representations, evidenced by the undersigned officer initialing either the one 3.a. representation or the six 3.b. representations in the spaces provided below:

   3.a. Participant transacts in PJM’s FTR markets with the sole intent to hedge congestion risk in connection with either obligations Participant has to serve load or rights Participant has to generate electricity in the PJM Region (“physical

[1] As used in this representation, the term “appropriate” as used with respect to training means training that is (i) comparable to generally accepted practices in the energy trading industry, and (ii) commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the participant.

[2] As used in this representation, a Participant’s “independent risk management function” can include appropriate corporate persons or bodies that are independent of the Participant’s trading functions, such as a risk management committee, a risk officer, a Participant’s board or board committee, or a board or committee of the Participant’s parent company.

transactions") and monitors all of the Participant's FTR market activity to endeavor to ensure that its FTR positions, considering both the size and pathways of the positions, are either generally proportionate to or generally do not exceed the Participant's physical transactions, and remain generally consistent with the Participant's intention to hedge its physical transactions.__________

3.b. On no less than a weekly basis, Participant values its FTR positions and engages in a probabilistic assessment of the hypothetical risk of such positions using analytically based methodologies, predicated on the use of industry accepted valuation methodologies.__________

Such valuation and risk assessment functions are performed either by persons within Participant's organization independent from those trading in PJM's FTR markets or by an outside firm qualified and with expertise in this area of risk management.__________

Having valued its FTR positions and quantified their hypothetical risks, Participant applies its written policies, procedures and controls to limit its risks using industry recognized practices, such as value-at-risk limitations, concentration limits, or other controls designed to prevent Participant from purposefully or unintentionally taking on risk that is not commensurate or proportional to Participant's financial capability to manage such risk.__________

Exceptions to Participant's written risk policies, procedures and controls applicable to Participant's FTR positions are documented and explain a reasoned basis for the granting of any exception.__________

Participant has provided to PJMSettlement, in accordance with Section I A. of Attachment Q to the PJM Tariff, a copy of its current governing risk management policies, procedures and controls applicable to its FTR trading activities.__________

If the risk management policies, procedures and controls applicable to Participant's FTR trading activities submitted to PJMSettlement were submitted prior to the current certification, Particpant certifies that no substantive changes have been made to such policies, procedures and controls applicable to its FTR trading activities since such submission.__________

4. Participant has appropriate personnel resources, operating procedures and technical abilities to promptly and effectively respond to all PJM communications and directions.__________

5. Participant has demonstrated compliance with the Minimum Capitalization criteria set forth in Attachment Q of the PJM Open Access Transmission Tariff that are applicable to the PJM market(s) in which Participant transacts, and is not aware of any change having occurred or being imminent that would invalidate such compliance.__________

6. All Participants must certify and initial in at least one of the four sections below:

   a. I certify that Participant qualifies as an “appropriate person” as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act or an “eligible contract participant” as that term is defined under Section 1a(18), or successor provision, of the Commodity Exchange Act. I certify that Participant will cease transacting in PJM’s Markets and notify PJMSettlement immediately if Participant no longer qualifies as an “appropriate person” or “eligible contract participant.”__________

      If providing financial statements to support Participant’s certification of qualification as an “appropriate person:”

      > I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $5 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

      If providing financial statements to support Participant’s certification of qualification as an “eligible contract participant:”

      > I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $10 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

   b. I certify that Participant has provided an unlimited Corporate Guaranty in a form acceptable to PJM as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant per Participant for which the issuer has issued an unlimited Corporate Guaranty. I certify that Participant will cease transacting PJM’s Markets and notify PJMSettlement immediately if issuer of the unlimited Corporate Guaranty for Participant no longer has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty.__________

I certify that the issuer of the unlimited Corporate Guaranty to Participant continues to have at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty. I acknowledge that PJM and PJMSettlement are relying upon my certifications to maintain compliance with federal regulatory requirements.__________

c. I certify that Participant fulfills the eligibility requirements of the Commodity Futures Trading Commission exemption order (78 F.R. 19880 – April 2, 2013) by being in the business of at least one of the following in the PJM Region as indicated below (initial those applicable):

    1. Generating electric energy, including Participants that resell physical energy acquired from an entity generating electric energy:__________

    2. Transmitting electric energy:__________

    3. Distributing electric energy delivered under Point-to-Point or Network Integration Transmission Service, including scheduled import, export and wheel through transactions:__________

    4. Other electric energy services that are necessary to support the reliable operation of the transmission system:__________

    Description only if c(4) is initialed:

    ____

    Further, I certify that Participant will cease transacting in PJM's Markets and notify PJMSettlement immediately if Participant no longer performs at least one of the functions noted above in the PJM Region. I acknowledge that PJM and PJMSettlement are relying on my certification to maintain compliance with federal energy regulatory requirements.__________

d. I certify that Participant has provided a letter of credit of $5 million or more to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Participant acknowledges cannot be utilized to meet its credit requirements to PJMSettlement. I acknowledge that PJM and PJMSettlement are relying on the provision of this letter of credit and my certification to maintain compliance with federal regulatory requirements.__________

7. I acknowledge that I have read and understood the provisions of Attachment Q of the PJM Tariff applicable to Participant's business in the PJM markets, including those provisions describing PJM's minimum participation requirements and the enforcement actions available to PJMSettlement of a Participant not satisfying those requirements. I acknowledge that the information provided herein is true and accurate to the best of my belief and knowledge after due investigation. In addition, by signing this Certification, I

acknowledge the potential consequences of making incomplete or false statements in this Certification.___________

Date: ______________________________ ____________________________________

(Signature)

Print Name: ____________________________________

Title: ____________________________________

ATTACHMENT Q

PJM CREDIT POLICY

POLICY STATEMENT:

It is the policy of PJM Interconnection, LLC ("PJM") that prior to an entity participating in the PJM Markets, or in order to take Transmission Service, the entity must demonstrate its ability to meet PJMSettlement's credit requirements.

Prior to becoming a Market Participant, Transmission Customer, and/or Member of PJM, PJMSettlement must accept and approve a Credit Application (including Credit Agreement) from such entity and establish a Working Credit Limit with PJMSettlement. PJMSettlement shall approve or deny an accepted Credit Application on the basis of a complete credit evaluation including, but not be limited to, a review of financial statements, rating agency reports, and other pertinent indicators of credit strength.

POLICY INTENT:

This credit policy describes requirements for: (1) the establishment and maintenance of credit by Market Participants, Transmission Customers, and entities seeking either such status (collectively "Participants"), pursuant to one or more of the Agreements, and (2) forms of security that will be deemed acceptable (hereinafter the "Financial Security") in the event that the Participant does not satisfy the financial or other requirements to establish Unsecured Credit.

This policy also sets forth the credit limitations that will be imposed on Participants in order to minimize the possibility of failure of payment for services rendered pursuant to the Agreements, and conditions that will be considered an event of default pursuant to this policy and the Agreements.

These credit rules may establish certain set-asides of credit for designated purposes (such as for FTR or RPM activity). Such set-asides shall be construed to be applicable to calculation of credit requirements only, and shall not restrict PJMSettlement's ability to apply such designated credit to any obligation(s) in case of a default.

PJMSettlement may post on PJM's web site, and may reference on OASIS, a supplementary document which contains additional business practices (such as algorithms for credit scoring) that are not included in this document. Changes to the supplementary document will be subject to stakeholder review and comment prior to implementation. PJMSettlement may specify a required compliance date, not less than 15 days from notification, by which time all Participants must comply with provisions that have been revised in the supplementary document.

APPLICABILITY:

This policy applies to all Participants.

IMPLEMENTATION:

I. CREDIT EVALUATION

Each Participant will be subject to a complete credit evaluation in order for PJMSettlement to determine creditworthiness and to establish an **Unsecured Credit Allowance**, if applicable; provided, however, that a Participant need not provide the information specified in section I.A or I.B if it notifies PJMSettlement in writing that it does not seek any Unsecured Credit Allowance. PJMSettlement will identify any necessary Financial Security requirements and establish a Working Credit Limit for each Participant. In addition, PJMSettlement will perform follow-up credit evaluations on at least an annual basis.

If a **Corporate Guaranty** is being utilized to establish credit for a Participant, the guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

PJMSettlement will provide a Participant, upon request, with a written explanation for any change in credit levels or collateral requirements. PJMSettlement will provide such explanation within ten Business Days.

If a Participant believes that either its level of unsecured credit or its collateral requirement has been incorrectly determined, according to this credit policy, then the Participant may send a request for reconsideration in writing to PJMSettlement. Such a request should include:

- A citation to the applicable section(s) of the PJMSettlement credit policy along with an explanation of how the respective provisions of the credit policy were not carried out in the determination as made

- A calculation of what the Participant believes should be the correct credit level or collateral requirement, according to terms of the credit policy

PJMSettlement will reconsider the determination and will provide a written response as promptly as practical, but no longer than ten Business Days of receipt of the request. If the Participant still feels that the determination is incorrect, then the Participant may contest that determination. Such contest should be in written form, addressed to PJMSettlement, and should contain:

♦ A complete copy of the Participant’s earlier request for reconsideration, including citations and calculations

♦ A copy of PJMSettlement’s written response to its request for reconsideration

♦ An explanation of why it believes that the determination still does not comply with the credit policy

PJMSettlement will investigate and will respond to the Participant with a final determination on the matter as promptly as practical, but no longer than 20 Business Days.

Neither requesting reconsideration nor contesting the determination following such request shall relieve or delay Participant's responsibility to comply with all provisions of this credit policy.

A. Initial Credit Evaluation

In completing the initial credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor’s, Moody’s Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit with its application audited financial statements for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the Participant, if shorter. All financial and related information considered for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement.

The information should include, but not be limited to, the following:

a. If publicly traded:
   - i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
   - ii. Form 8-K reports disclosing Material changes, if any.

b. If privately held:
   - i. Management’s Discussion & Analysis
   - ii. Report of Independent Accountants
   - iii. Financial Statements, including:
     - Balance Sheet
     - Income Statement
     - Statement of Cash Flows
     - Statement of Stockholder’s Equity
   - iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) References

PJMSettlement may request Participants to provide with their applications at least one (1) bank and three (3) utility credit references. In the case where a Participant does not have the required utility references, trade payable vendor references may be substituted.

4) Litigation, Commitments and Contingencies

Each Participant is also required to provide with its application information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJMSettlement or are applying for membership with PJMSettlement. Each Participant is also required to disclose the existence of any ongoing investigations by the Securities and Exchange Commission ("SEC"), Federal Energy Regulatory Commission ("FERC"), Commodity Futures Trading Commission ("CFTC"), or any other governing, regulatory, or standards body. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.

B. Ongoing Credit Evaluation

On at least an annual basis, PJMSettlement will perform follow-up credit evaluations on all Participants. In completing the credit evaluation, PJMSettlement will consider:

1) Rating Agency Reports

In evaluating credit strength, PJMSettlement will review rating agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other nationally known rating agencies. The focus of the review will be on senior unsecured debt ratings; however, PJMSettlement will consider other ratings if senior unsecured debt ratings are not available.

2) Financial Statements and Related Information

Each Participant must submit audited annual financial statements as soon as they become available and no later than 120 days after fiscal year end. Each Participant is also required to provide PJMSettlement with quarterly financial statements promptly upon their issuance, but no later than 60 days after the end of each quarter. All financial and related information considered

for a Credit Score must be audited by an outside entity, and must be accompanied by an unqualified audit letter acceptable to PJMSettlement. If financial statements are not provided within the timeframe required, the Participant may not be granted an Unsecured Credit Allowance.

The information should include, but not be limited to, the following:

a. If publicly traded:
    i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively.
    ii. Form 8-K reports disclosing Material changes, if any, immediately upon issuance.

b. If privately held:
    i. Management's Discussion & Analysis
    ii. Report of Independent Accountants
    iii. Financial Statements, including:
        - Balance Sheet
        - Income Statement
        - Statement of Cash Flows
        - Statement of Stockholder's Equity
    iv. Notes to Financial Statements

If the above information is available on the Internet, the Participant may provide a letter stating where such statements may be located and retrieved by PJMSettlement. For certain Participants, some of the above financial submittals may not be applicable, and alternate requirements may be specified by PJMSettlement.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

3) Material Changes

Each Participant is responsible for informing PJMSettlement immediately, in writing, of any Material change in its financial condition. However, PJMSettlement may also independently establish from available information that a Participant has experienced a Material change in its financial condition without regard to whether such Participant has informed PJMSettlement of the same.

For the purpose of this policy, a Material change in financial condition may include, but not be limited to, any of the following:

a. a downgrade of any debt rating by any rating agency;
b. being placed on a credit watch with negative implications by any rating agency;
c. a bankruptcy filing;
d. insolvency;

e. a report of a quarterly or annual loss or a decline in earnings of ten percent or more compared to the prior period;
f. restatement of prior financial statements;
g. the resignation of key officer(s);
h. the filing of a lawsuit that could adversely impact any current or future financial results by ten percent or more;
i. financial default in another organized wholesale electric market futures exchange or clearing house;
j. revocation of a license or other authority by any Federal or State regulatory agency; where such license or authority is necessary or important to the Participants continued business for example, FERC market-based rate authority, or State license to serve retail load; or
k. a significant change in credit default spreads, market capitalization, or other market-based risk measurement criteria, such as a recent increase in Moody's KMV Expected Default Frequency (EDF^{tm}) that is noticeably greater than the increase in its peers' EDF^{tm} rates, or a collateral default swap (CDS) premium normally associated with an entity rated lower than investment grade.

If PJMSettlement determines that a Material change in the financial condition of the Participant has occurred, it may require the Participant to provide Financial Security within two Business Days, in an amount and form approved by PJMSettlement. If the Participant fails to provide the required Financial Security, the Participant shall be in default under this credit policy.

In the event that PJMSettlement determines that a Material change in the financial condition of a Participant warrants a requirement to provide Financial Security, PJMSettlement shall provide the Participant with a written explanation of why such determination was made. However, under no circumstances shall the requirement that a Participant provide the requisite Financial Security be deferred pending the issuance of such written explanation.

4) Litigation, Commitments, and Contingencies

Each Participant is also required to provide information as to any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon initiation or change or as requested by PJMSettlement.

5) Other Disclosures

Each Participant is required to disclose any Affiliates that are currently Members of PJM or are applying for membership within PJM. Each Participant is also required to disclose the existence of any ongoing investigations by the SEC, FERC, CFTC or any other governing, regulatory, or standards body. These disclosures shall be made upon initiation or change, or as requested by PJMSettlement.

C. Corporate Guaranty

If a Corporate Guaranty is being utilized to establish credit for a Participant, the Guarantor will be evaluated and the Unsecured Credit Allowance or Financial Security requirement will be based on the financial strength of the Guarantor.

An irrevocable and unconditional Corporate Guaranty may be utilized as part of the credit evaluation process, but will not be considered a form of Financial Security. The Corporate Guaranty will be considered a transfer of credit from the Guarantor to the Participant. The Corporate Guaranty must guarantee the (i) full and prompt payment of all amounts payable by the Participant under the Agreements, and (ii) performance by the Participant under this policy.

The Corporate Guaranty should clearly state the identities of the "Guarantor," "Beneficiary" (PJMSettlement) and "Obligor" (Participant). The Corporate Guaranty must be signed by an officer of the Guarantor, and must demonstrate that it is duly authorized in a manner acceptable to PJMSettlement. Such demonstration may include either a Corporate Seal on the Guaranty itself, or an accompanying executed and sealed Secretary's Certificate noting that the Guarantor was duly authorized to provide such Corporate Guaranty and that the person signing the Corporate Guaranty is duly authorized, or other manner acceptable to PJMSettlement.

A Participant supplying a Corporate Guaranty must provide the same information regarding the Guarantor as is required in the "Initial Credit Evaluation" §I.A. and the "Ongoing Evaluation" §I.B. of this policy, including providing the Rating Agency Reports, Financial Statements and Related Information, References, Litigation Commitments and Contingencies, and Other Disclosures. A Participant supplying a Foreign or Canadian Guaranty must also satisfy the requirements of §I.C.1 or §I.C.2, as appropriate.

If there is a Material change in the financial condition of the Guarantor or if the Corporate Guaranty comes within 30 days of expiring without renewal, the Participant will be required to provide Financial Security either in the form of a cash deposit or a letter of credit. Failure to provide the required Financial Security within two Business Days after request by PJMSettlement will constitute an event of default under this credit policy. A Participant may request PJMSettlement to perform a credit evaluation in order to determine creditworthiness and to establish an Unsecured Credit Allowance, if applicable. If PJMSettlement determines that a Participant does qualify for a sufficient Unsecured Credit Allowance, then Financial Security will not be required.

The PJMSettlement Credit Application contains an acceptable form of Corporate Guaranty that should be utilized by a Participant choosing to establish its credit with a Corporate Guaranty. If the Corporate Guaranty varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a Corporate Guaranty and meeting the policy provisions are the responsibility of the Participant.

1) Foreign Guaranties

A Foreign Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in a country other than the United States or Canada. The entity providing a Foreign Guaranty on behalf of a Participant is a Foreign Guarantor. A Participant may provide a Foreign

Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met:

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Foreign Guaranty at any time, including for material adverse circumstances or occurrences.

a. A Foreign Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.
   iv. Will not be accepted towards a Participant's Unsecured Credit Allowance for more than the following limits, depending on the Foreign Guarantor's credit rating:

Rating of Foreign Guarantor	Maximum Accepted Guaranty if Country Rating is AAA	Maximum Accepted Guaranty if Country Rating is AA+
A- and above	USD50,000,000	USD30,000,000
BBB+	USD30,000,000	USD20,000,000
BBB	USD10,000,000	USD10,000,000
BBB- or below	USD 0	USD 0

   v. May not exceed 50% of the Participant's total credit, if the Foreign Grantor is rated less than BBB+.

b. A Foreign Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Foreign Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must have a Senior Unsecured (or equivalent, in PJMSettlement's sole discretion) rating of BBB (one notch above BBB-) or greater by any and all agencies that provide rating coverage of the entity.
   vi. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance

vii. Must provide a Secretary’s Certificate certifying the adoption of Corporate Resolutions:
   1. Authorizing and approving the Guaranty; and
   2. Authorizing the Officers to execute and deliver the Guaranty on behalf of the Guarantor.

viii. Must be domiciled in a country with a minimum long-term sovereign (or equivalent) rating of AA+/Aa1, with the following conditions:
   1. Sovereign ratings must be available from at least two rating agencies acceptable to PJMSettlement (e.g. S&P, Moody’s, Fitch, DBRS).
   2. Each agency’s sovereign rating for the domicile will be considered to be the lowest of: country ceiling, senior unsecured government debt, long-term foreign currency sovereign rating, long-term local currency sovereign rating, or other equivalent measures, at PJMSettlement’s sole discretion.
   3. Whether ratings are available from two or three agencies, the lowest of the two or three will be used.

ix. Must be domiciled in a country that recognizes and enforces judgments of US courts.

x. Must demonstrate financial commitment to activity in the United States as evidenced by one of the following:
   1. American Depository Receipts (ADR) are traded on the New York Stock Exchange, American Stock Exchange, or NASDAQ.
   2. Equity ownership worth over USD100,000,000 in the wholly-owned or majority owned subsidiaries in the United States.

xi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this credit policy.

xii. Must pay for all expenses incurred by PJMSettlement related to reviewing and accepting a foreign guaranty beyond nominal in-house credit and legal review.

xiii. Must, at its own cost, provide PJMSettlement with independent legal opinion from an attorney/solicitor of PJMSettlement’s choosing and licensed to practice law in the United States and/or Guarantor’s domicile, in form and substance acceptable to PJMSettlement in its sole discretion, confirming the enforceability of the Foreign Guaranty, the Guarantor’s legal authorization to grant the Guaranty, the conformance of the Guaranty, Guarantor, and Guarantor's domicile to all of these requirements, and such other matters as PJMSettlement may require in its sole discretion.

2) Canadian Guaranties

A Canadian Guaranty is a Corporate Guaranty that is provided by an Affiliate entity that is domiciled in Canada and satisfies all of the provisions below. The entity providing a Canadian Guaranty on behalf of a Participant is a Canadian Guarantor. A Participant may provide a Canadian Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJMSettlement provided that all of the following conditions are met.

PJMSettlement reserves the right to deny, reject, or terminate acceptance of any Canadian Guaranty at any time for reasonable cause, including adverse material circumstances.

a. A Canadian Guaranty:
   i. Must contain provisions equivalent to those contained in PJMSettlement's standard form of Foreign Guaranty with any modifications subject to review and approval by PJMSettlement counsel.
   ii. Must be denominated in US currency.
   iii. Must be written and executed solely in English, including any duplicate originals.

b. A Canadian Guarantor:
   i. Must satisfy all provisions of the PJM credit policy applicable to domestic Guarantors.
   ii. Must be an Affiliate of the Participant.
   iii. Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.
   iv. Must be rated by at least one Rating Agency acceptable to PJMSettlement; the credit strength of a Canadian Guarantor may not be determined based on an evaluation of its financials without an actual credit rating as well.
   v. Must provide financials in GAAP format or other format acceptable to PJMSettlement with clear representation of net worth, intangible assets, and any other information PJMSettlement may require in order to determine the entity's Unsecured Credit Allowance.

   vi. Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Credit Policy.

Ia. MINIMUM PARTICIPATION REQUIREMENTS

A. PJM Market Participation Eligibility Requirements

To be eligible to transact in PJM Markets, a Market Participant must demonstrate in accordance with the Risk Management and Verification processes set forth below that it qualifies in one of the following ways:

1. an "appropriate person," as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act, or;

2. an "eligible contract participant," as that term is defined in Section 1a(18), or successor provision, of the Commodity Exchange Act, or;

3. a business entity or person who is in the business of: (1) generating, transmitting, or distributing electric energy, or (2) providing electric energy services that are necessary to support the reliable operation of the transmission system, or;

4. a Market Participant seeking eligibility as an “appropriate person” providing an unlimited Corporate Guaranty in a form acceptable to PJMSettlement as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty, or;

5. a Market Participant providing a letter of credit of at least $5 million to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJMSettlement.

If, at any time, a Market Participant cannot meet the eligibility requirements set forth above, it shall immediately notify PJMSettlement and immediately cease conducting transactions in the PJM Markets. PJMSettlement shall terminate a Market Participant’s transaction rights in the PJM Markets if, at any time, it becomes aware that the Market Participant does not meet the minimum eligibility requirements set forth above.

In the event that a Market Participant is no longer able to demonstrate it meets the minimum eligibility requirements set forth above, and possesses, obtains or has rights to possess or obtain, any open or forward positions in PJM’s Markets, PJMSettlement may take any such action it deems necessary with respect to such open or forward positions, including, but not limited to, liquidation, transfer, assignment or sale; provided, however, that the Market Participant will, notwithstanding its ineligibility to participate in the PJM Markets, be entitled to any positive market value of those positions, net of any obligations due and owing to PJM and/or PJMSettlement.

B. Risk Management and Verification

All Participants shall provide to PJMSettlement an executed copy of the annual certification set forth in Appendix 1 to this Attachment Q. This certification shall be provided before an entity is eligible to participate in the PJM Markets and shall be initially submitted to PJMSettlement together with the entity’s Credit Application. Thereafter, it shall be submitted each calendar year by all Participants during a period beginning on January 1 and ending April 30, except that new Participants who became eligible to participate in PJM markets during the period of January through April shall not be required to resubmit such certification until the following calendar year. Except for certain FTR Participants (discussed below) or in cases of manifest error, PJMSettlement will accept such certifications as a matter of course and Participants will not need further notice from PJMSettlement before commencing or maintaining their eligibility to participate in PJM markets. A Participant that fails to provide its annual certification by April 30 shall be ineligible to transact in the PJM markets and PJM will disable the Participant’s access to the PJM markets until such time as PJMSettlement receives the Participant’s certification.

Participants acknowledge and understand that the annual certification constitutes a representation upon which PJMSettlement will rely. Such representation is additionally made under the PJM Tariff, filed with and accepted by FERC, and any inaccurate or incomplete statement may subject the Participant to action by FERC. Failure to comply with any of the criteria or

requirements listed herein or in the certification may result in suspension of a Participant's transaction rights in the PJM markets.

Certain FTR Participants (those providing representations found in paragraph 3.b of the annual certification set forth in Appendix 1 to this Attachment Q) are additionally required to submit to PJMSettlement (at the time they make their annual certification) a copy of their current governing risk control policies, procedures and controls applicable to their FTR trading activities, except that if no substantive changes have been made to such policies, practices and/or controls applicable to their FTR trading activities, they may instead submit to PJMSettlement a certification stating that no changes have been made. PJMSettlement will review such documentation to verify that it appears generally to conform to prudent risk management practices for entities trading in FTR-type markets. If principles or best practices relating to risk management in FTR-type markets are published, as may be modified from time to time, by a third-party industry association, such as the Committee of Chief Risk Officers, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the fundamental sufficiency of the FTR Participant's risk controls. Those FTR Participants subject to this provision shall make a one-time payment of $1,000.00 to PJMSettlement to cover costs associated with review and verification. Thereafter, if such FTR Participant's risk policies, procedures and controls applicable to its FTR trading activities change substantively, it shall submit such modified documentation, without charge, to PJMSettlement for review and verification at the time it makes its annual certification. Such FTR Participant's continued eligibility to participate in the PJM FTR markets is conditioned on PJMSettlement notifying such FTR Participant that its annual certification, including the submission of its risk policies, procedures and controls, has been accepted by PJMSettlement. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph, however, in all circumstances, PJMSettlement and any third-party it may retain will treat as confidential the documentation provided by an FTR Participant under this paragraph, consistent with the applicable provisions of PJM's Operating Agreement.

An FTR Participant that makes the representation in paragraph 3.a of the annual certification understand that PJMSettlement, given the visibility it has over a Participant's overall market activity in performing billing and settlement functions, may at any time request the FTR Participant provide additional information demonstrating that it is in fact eligible to make the representation in paragraph 3.a of the annual certification. If such additional information is not provided or does not, in PJMSettlement's judgment, demonstrate eligibility to make the representation in paragraph 3.a of the annual certification, PJMSettlement will require the FTR Participant to instead make the representations required in paragraph 3.b of the annual certification, including representing that it has submitted a copy of its current governing risk control policies, procedures and controls applicable to its FTR trading activities. If the FTR Participant cannot or does not make those representations as required in paragraph 3.b of the annual certification, then PJM will terminate the FTR Participant's rights to purchase FTRs in the FTR market and may terminate the FTR Participant's rights to sell FTRs in the PJM FTR market.

PJMSettlement shall also conduct a periodic compliance verification process to review and verify, as applicable, Participants' risk management policies, practices, and procedures pertaining to the Participants' activities in the PJM markets. Such review shall include verification that:

1. The risk management framework is documented in a risk policy addressing market, credit and liquidity risks.
2. The Participant maintains an organizational structure with clearly defined roles and responsibilities that clearly segregates trading and risk management functions.
3. There is clarity of authority specifying the types of transactions into which traders are allowed to enter.
4. The Participant has requirements that traders have adequate training relative to their authority in the systems and PJM markets in which they transact.
5. As appropriate, risk limits are in place to control risk exposures.
6. Reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization.
7. Processes are in place for qualified independent review of trading activities.
8. As appropriate, there is periodic valuation or mark-to-market of risk positions.

If principles or best practices relating to risk management in PJM-type markets are published, as may be modified from time to time, by a third-party industry association, PJMSettlement may, following stakeholder discussion and with no less than six months prior notice to stakeholders, apply such principles or best practices in determining the sufficiency of the Participant's risk controls. PJMSettlement may select Participants for review on a random basis and/or based on identified risk factors such as, but not limited to, the PJM markets in which the Participant is transacting, the magnitude of the Participant's transactions in the PJM markets, or the volume of the Participant's open positions in the PJM markets. Those Participants notified by PJMSettlement that they have been selected for review shall, upon 14 calendar days notice, provide a copy of their current governing risk control policies, procedures and controls applicable to their PJM market activities and shall also provide such further information or documentation pertaining to the Participants' activities in the PJM markets as PJMSettlement may reasonably request. Participants selected for risk management verification through a random process and satisfactorily verified by PJMSettlement shall be excluded from such verification process based on a random selection for the subsequent two years. PJMSettlement shall annually randomly select for review no more than 20% of the Participants in each member sector.

Each selected Participant's continued eligibility to participate in the PJM markets is conditioned upon PJMSettlement notifying the Participant of successful completion of PJMSettlement's verification of the Participant's risk management policies, practices and procedures, as discussed

herein. However, if PJMSettlement notifies the Participant in writing that it could not successfully complete the verification process, PJMSettlement shall allow such Participant 14 calendar days to provide sufficient evidence for verification prior to declaring the Participant as ineligible to continue to participate in PJM's markets, which declaration shall be in writing with an explanation of why PJMSettlement could not complete the verification. If, prior to the expiration of such 14 calendar days, the Participant demonstrates to PJMSettlement that it has filed with the Federal Energy Regulatory Commission an appeal of PJMSettlement's risk management verification determination, then the Participant shall retain its transaction rights, pending the Commission's determination on the Participant's appeal. PJMSettlement may retain outside expertise to perform the review and verification function described in this paragraph. PJMSettlement and any third party it may retain will treat as confidential the documentation provided by a Participant under this paragraph, consistent with the applicable provisions of the Operating Agreement. If PJMSettlement retains such outside expertise, a Participant may direct in writing that PJMSettlement perform the risk management review and verification for such Participant instead of utilizing a third party, provided however, that employees and contract employees of PJMSettlement and PJM shall not be considered to be such outside expertise or third parties.

Participants are solely responsible for the positions they take and the obligations they assume in PJM markets. PJMSettlement hereby disclaims any and all responsibility to any Participant or PJM Member associated with Participant's submitting or failure to submit its annual certification or PJMSettlement's review and verification of an FTR Participant's risk policies, procedures and controls. Such review and verification is limited to demonstrating basic compliance by an FTR Participant with the representation it makes under paragraph 3.b of its annual certification showing the existence of written policies, procedures and controls to limit its risk in PJM's FTR markets and does not constitute an endorsement of the efficacy of such policies, procedures or controls.

C. Capitalization

In addition to the Annual Certification requirements in Appendix 1 to this Attachment Q, a Participant must demonstrate that it meets the minimum financial requirements appropriate for the PJM market(s) in which it transacts by satisfying either the Minimum Capitalization or the Provision of Collateral requirements listed below:

1. Minimum Capitalization

FTR Participants must demonstrate a tangible net worth in excess of $1 million or tangible assets in excess of $10 million. Other Participants must demonstrate a tangible net worth in excess of $500,000 or tangible assets in excess of $5 million.

a. In either case, consideration of "tangible" assets and net worth shall exclude assets (net of any matching liabilities, assuming the result is a positive value) which PJMSettlement reasonably believes to be restricted, highly risky, or potentially unavailable to settle a claim in the event of default. Examples include, but are not

limited to, restricted assets and Affiliate assets, derivative assets, goodwill, and other intangible assets.

b. Demonstration of “tangible” assets and net worth may be satisfied through presentation of an acceptable Corporate Guaranty, provided that both:

(i) the guarantor is an affiliate company that satisfies the tangible net worth or tangible assets requirements herein, and;

(ii) the Corporate Guaranty is either unlimited or at least $500,000.

If the Corporate Guaranty presented by the Participant to satisfy these Capitalization requirements is limited in value, then the Participant’s resulting Unsecured Credit Allowance shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this Credit Policy, or:

(2) the face value of the Corporate Guaranty, reduced by $500,000 and further reduced by 10%. (For example, a $10.5 million Corporate Guaranty would be reduced first by $500,000 to $10 million and then further reduced 10% more to $9 million. The resulting $9 million would be the Participant’s Unsecured Credit Allowance available through the Corporate Guaranty).

In the event that a Participant provides collateral in addition to a limited Corporate Guaranty to increase its available credit, the value of such collateral shall be reduced by 10%. This reduced value shall be deemed Financial Security and available to satisfy the requirements of this Credit Policy.

Demonstrations of capitalization must be presented in the form of audited financial statements for the Participant’s most recent fiscal year.

2. Provision of Collateral

If a Participant does not demonstrate compliance with its applicable Minimum Capitalization Requirements above, it may still qualify to participate in PJM’s markets by posting additional collateral, subject to the terms and conditions set forth herein.

Any collateral provided by a Participant unable to satisfy the Minimum Capitalization Requirements above will be restricted in the following manner:

i. Collateral provided by FTR Participants shall be reduced by $500,000 and then further reduced by 10%. This reduced amount shall be considered the Financial Security provided by the Participant and available to satisfy requirements of this Credit Policy.

ii. Collateral provided by other Participants that engage in Virtual Transactions or Export Transactions shall be reduced by $200,000 and then further reduced by 10%. This reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

iii. Collateral provided by other Participants that do not engage in Virtual Transactions or Export Transactions shall be reduced by 10%, and this reduced value shall be considered Financial Security available to satisfy requirements of this Credit Policy.

In the event a Participant that satisfies the Minimum Participation Requirements through provision of collateral also provides a Corporate Guaranty to increase its available credit, then the Participant's resulting Unsecured Credit Allowance conveyed through such Guaranty shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this credit policy, or,

(2) the face value of the Guaranty, reduced by 10%.

II. CREDIT ALLOWANCE AND WORKING CREDIT LIMIT

PJMSettlement's credit evaluation process will include calculating a Credit Score for each Participant. The credit score will be utilized to determine a Participant's Unsecured Credit Allowance.

Participants who do not qualify for an Unsecured Credit Allowance will be required to provide Financial Security based on their Peak Market Activity, as provided below.

A corresponding Working Credit Limit will be established based on the Unsecured Credit Allowance and/or the Financial Security provided.

Where Participant of PJM are considered Affiliates, Unsecured Credit Allowances and Working Credit Limits will be established for each individual Participant, subject to an aggregate maximum amount for all Affiliates as provided for in §II.F of this policy.

In its credit evaluation of Cooperatives and Municipalities, PJMSettlement may request additional information as part of the overall financial review process and may also consider qualitative factors in determining financial strength and creditworthiness.

A. Credit Score

For participants with credit ratings, a Credit Score will be assigned based on their senior unsecured credit rating and credit watch status as shown in the table below. If an explicit senior unsecured rating is not available, PJMSettlement may impute an equivalent rating from other ratings that are available. For Participants without a credit rating, but who wish to be considered for unsecured Credit, a Credit Score will be generated from PJMSettlement's review and analysis of various factors that are predictors of financial strength and creditworthiness. Key factors in the scoring process include, financial ratios, and years in business. PJMSettlement will consistently apply the measures it uses in determining Credit Scores. The credit scoring methodology details are included in a supplementary document available on OASIS.

Rated Entities Credit Scores

Rating	Score	Score Modifier	
		Credit Watch Negative	Credit Watch Positive
AAA	100	-1.0	0.0
AA+	99	-1.0	0.0
AA	99	-1.0	0.0
AA-	98	-1.0	0.0
A+	97	-1.0	0.0
A	96	-2.0	0.0
A-	93	-3.0	1.0
BBB+	88	-4.0	2.0
BBB	78	-4.0	2.0
BBB-	65	-4.0	2.0
BB+ and below	0	0.0	0.0

B. Unsecured Credit Allowance

PJMSettlement will determine a Participant's Unsecured Credit Allowance based on its Credit Score and the parameters in the table below. The maximum Unsecured Credit Allowance is the lower of:

1) A percentage of the Participant's Tangible Net Worth, as stated in the table below, with the percentage based on the Participant's credit score; and

2) A dollar cap based on the credit score, as stated in the table below:

Credit Score	Tangible Net Worth Factor	Maximum Unsecured Credit Allowance ($ Million)
91-100	2.125 – 2.50%	$50
81-90	1.708 – 2.083%	$42
71-80	1.292 – 1.667%	$33
61-70	0.875 – 1.25%	$7
51-60	0.458 – 0.833%	$0-$2
50 and Under	0%	$0

If a Corporate Guaranty is utilized to establish an Unsecured Credit Allowance for a Participant, the value of a Corporate Guaranty will be the lesser of:

- The limit imposed in the Corporate Guaranty;
- The Unsecured Credit Allowance calculated for the Guarantor; and
- A portion of the Unsecured Credit Allowance calculated for the Guarantor in the case of Affiliated Participants.

PJMSettlement has the right at any time to modify any Unsecured Credit Allowance and/or require additional Financial Security as may be deemed reasonably necessary to support current market activity. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.

PJMSettlement will maintain a posting of each Participant's unsecured Credit Allowance, along with certain other credit related parameters, on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

C. Seller Credit

Participants that have maintained a Net Sell Position for each of the prior 12 months are eligible for Seller Credit, which is an additional form of Unsecured Credit. A Participant's Seller Credit will be equal to sixty percent of the Participant's thirteenth smallest weekly Net Sell Position invoiced in the past 52 weeks.

Each Participant receiving Seller Credit must maintain both its Seller Credit and its Total Net Sell Position equal to or greater than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided.

For Participants receiving Seller Credit, PJMSettlement may forecast the Participant's Total Net Sell Position considering the Participant's current Total Net Sell Position, recent trends in the Participant's Total Net Sell Position, and other information available to PJMSettlement, such as, but not limited to, known generator outages, changes in load responsibility, and bilateral

transactions impacting the Participant. If PJMSettlement's forecast ever indicates that the Participant's Total Net Sell Position may in the future be less than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided, then PJMSettlement may require Financial Security as needed to cover the difference. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default.

Any Financial Security required by PJMSettlement pursuant to these provisions for Seller Credit will be returned once the requirement for such Financial Security has ended. Seller Credit may not be conveyed to another entity through use of a guaranty. Seller Credit shall be subject to the cap on available Unsecured Credit set forth in Section II.F.

D. Peak Market Activity and Financial Security Requirement

A PJM Participant or Applicant that has an insufficient Unsecured Credit Allowance to satisfy its Peak Market Activity will be required to provide Financial Security such that its Unsecured Credit Allowance and Financial Security together are equal to its Peak Market Activity in order to secure its transactional activity in the PJM Market.

Peak Market Activity for Participants will be determined semi-annually beginning in the first complete billing week in the months of April and October. Peak Market Activity shall be the greater of the initial Peak Market Activity, as explained below, or the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two, or three week period, ending within a respective semi-annual period. However, Peak Market Activity shall not exceed the greatest amount invoiced for the Participant's transaction activity for all PJM markets and services in any rolling one, two or three week period in the prior 52 weeks.

Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

The initial Peak Market Activity for Applicants will be determined by PJMSettlement based on a review of an estimate of their transactional activity for all PJM markets and services over the next 52 weeks, which the Applicant shall provide to PJMSettlement.

The initial Peak Market Activity for Participants, calculated at the beginning of each respective semi-annual period, shall be the three-week average of all non-zero invoice totals over the previous 52 weeks. This calculation shall be performed and applied within three business days following the day the invoice is issued for the first full billing week in the current semi-annual period.

Prepayments shall not affect Peak Market Activity unless otherwise agreed to in writing pursuant to this Credit Policy.

All Peak Market Activity calculations shall take into account reductions of invoice values effectuated by early payments which are applied to reduce a Participant's Peak Market Activity

as contemplated by other terms of the Credit Policy; provided that the initial Peak Market Activity shall not be less than the average value calculated using the weeks for which no early payment was made.

A Participant may reduce its Financial Security Requirement by agreeing in writing (in a form acceptable to PJMSettlement) to make additional payments, including prepayments, as and when necessary to ensure that such Participant's Total Net Obligation at no time exceeds such reduced Financial Security Requirement.

PJMSettlement may, at its discretion, adjust a Participant's Financial Security Requirement if PJMSettlement determines that the Peak Market Activity is not representative of such Participant's expected activity, as a consequence of known, measurable, and sustained changes. Such changes may include the loss (without replacement) of short-term load contracts, when such contracts had terms of three months or more and were acquired through state-sponsored retail load programs, but shall not include short-term buying and selling activities.

PJMSettlement may waive the Financial Security Requirement for a Participant that agrees in writing that it shall not, after the date of such agreement, incur obligations under any of the Agreements. Such entity's access to all electronic transaction systems administered by PJM shall be terminated.

PJMSettlement will maintain a posting of each Participant's Financial Security Requirement on the PJM web site in a secure, password-protected location. Such information will be updated at least weekly. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

E. Working Credit Limit

PJMSettlement will establish a Working Credit Limit for each Participant against which its **Total Net Obligation** will be monitored. The Working Credit Limit is defined as 75% of the Financial Security provided to PJMSettlement and/or 75% of the Unsecured Credit Allowance determined by PJMSettlement based on a credit evaluation, as reduced by any applicable credit requirement determinants defined in this policy. A Participant's Total Net Obligation should not exceed its Working Credit Limit.

> Example: After a credit evaluation by PJMSettlement, a Participant is deemed able to support an Unsecured Credit Allowance of $10.0 million. The Participant will be assigned a Working Credit Limit of $8.5 million. PJMSettlement will monitor the Participant's Total Net Obligations against the Working Credit Limit.

A Participant with an Unsecured Credit Allowance may choose to provide Financial Security in order to increase its Working Credit Limit. A Participant with no Unsecured Credit Allowance may also choose to increase its Working Credit Limit by providing Financial Security in an amount greater than its Peak Market Activity.

If a Participant's Total Net Obligation approaches its Working Credit Limit, PJMSettlement may require the Participant to make an advance payment or increase its Financial Security in order to maintain its Total Net Obligation below its Working Credit Limit. Except as explicitly provided

below, advance payments shall not serve to reduce the Participant's Peak Market Activity for the purpose of calculating credit requirements.

> Example: After 10 days, and with 5 days remaining before the bill is due to be paid, a Participant approaches its $4.0 million Working Credit Limit. PJMSettlement may require a prepayment of $2.0 million in order that the Total Net Obligation will not exceed the Working Credit Limit.

If a Participant exceeds its Working Credit Limit or is required to make advance payments more than ten times during a 52-week period, PJMSettlement may require Financial Security in an amount as may be deemed reasonably necessary to support its Total Net Obligation.

A Participant receiving unsecured credit may make early payments up to ten times in a rolling 52-week period in order to reduce its Peak Market Activity for credit requirement purposes. Imputed Peak Market Activity reductions for credit purposes will be applied to the billing period for which the payment was received. Payments used as the basis for such reductions must be received prior to issuance or posting of the invoice for the relevant billing period. The imputed Peak Market Activity reduction attributed to any payment may not exceed the amount of Unsecured Credit for which the Participant is eligible.

F. Credit Limit Setting For Affiliates

If two or more Participants are Affiliates and each is being granted an Unsecured Credit Allowance and a corresponding Working Credit Limit, PJMSettlement will consider the overall creditworthiness of the Affiliated Participants when determining the Unsecured Credit Allowances and Working Credit Limits in order not to grant more Unsecured Credit than the overall corporation could support.

> **Example:** Participants A and B each have a $10.0 million Corporate Guaranty from their common parent, a holding company with an Unsecured Credit Allowance calculation of $12.0 million. PJMSettlement may limit the Unsecured Credit Allowance for each Participant to $6.0 million, so the total Unsecured Credit Allowance does not exceed the corporate total of $12.0 million.

PJMSettlement will work with Affiliated Participants to allocate the total Unsecured Credit Allowance among the Affiliates while assuring that no individual Participant, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. The aggregate Unsecured Credit for a Participant, including Unsecured Credit Allowance granted based on its own creditworthiness and any Unsecured Credit Allowance conveyed through a Guaranty shall not exceed $50 million. The aggregate Unsecured Credit for a group of Affiliates shall not exceed $50 million. A group of Affiliates subject to this cap shall request PJMSettlement to allocate the maximum Unsecured Credit and Working Credit Limit amongst the group, assuring that no individual Participant or common guarantor, shall exceed the Unsecured Credit level appropriate for its credit strength and activity.

G. Working Credit Limit Violations

1) Notification

A Participant is subject to notification when its Total Net Obligation to PJMSettlement approaches the Participant's established Working Credit Limit.

2) Suspension

A Participant that exceeds its Working Credit Limit is subject to suspension from participation in the PJM markets and from scheduling any future Transmission Service unless and until Participant's credit standing is brought within acceptable limits. A Participant will have two Business Days from notification to remedy the situation in a manner deemed acceptable by PJMSettlement. Additionally, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant's ongoing Transmission Service and participation in PJM Markets. Failure to comply with this policy will be considered an event of default under this credit policy.

H. PJM Administrative Charges

Financial Security held by PJMSettlement shall also secure obligations to PJM for PJM administrative charges.

I. Pre-existing Financial Security

PJMSettlement's credit requirements are applicable as of the effective date of the filing on May 5, 2010 by PJM and PJMSettlement of amendments to Attachment Q. Financial Security held by PJM prior to the effective date of such amendments shall be held by PJM for the benefit of PJMSettlement.

III. VIRTUAL TRANSACTION SCREENING

A. Credit and Financial Security

PJMSettlement does not require a Market Participant to establish separate or additional credit for submitting Virtual Transactions. If a Market Participant chooses to establish additional Financial Security and/or Unsecured Credit Allowance in order to increase its Credit Available for Virtual Transactions, the Market Participant's Working Credit Limit for Virtual Transactions shall be increased in accordance with the definition therof. The Financial Security and/or Unsecured Credit Allowance available to increase a Market Participant's Credit Available for Virtual Transactions shall be the amount of Financial Security and/or Unsecured Credit Allowance available after subtracting any credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy, as applicable.

If a Market Participant chooses to provide additional Financial Security in order to increase its **Credit Available for Virtual Transactions PJMSettlement** may establish a reasonable timeframe, not to exceed three months, for which such Financial Security must be maintained. PJMSettlement will not impose such restriction on a deposit unless a Market Participant is

notified prior to making the deposit. Such restriction, if applied, shall be applied to all future deposits by all Market Participants engaging in Virtual Transactions.

A Market Participant wishing to increase its Credit Available for Virtual Transactions by providing additional Financial Security may make the appropriate arrangements with PJMSettlement. PJMSettlement will make a good faith effort to make new Financial Security available as Credit Available for Virtual Transactions as soon as practicable after confirmation of receipt. In any event, however, Financial Security received and confirmed by noon on a business day will be applied (as provided under this policy) to Credit Available for Virtual Transactions no later than 10:00 am on the following business day. Receipt and acceptance of wired funds for cash deposit shall mean actual receipt by PJMSettlement's bank, deposit into PJMSettlement's customer deposit account, and confirmation by PJMSettlement that such wire has been received and deposited. Receipt and acceptance of letters of credit shall mean receipt of the original letter of credit or amendment thereto, and confirmation from PJMSettlement's credit and legal staffs that such letter of credit or amendment thereto conforms to PJMSettlement's requirements, which confirmation shall be made in a reasonable and practicable timeframe. To facilitate this process, bidders wiring funds for the purpose of increasing their Credit Available for Virtual Transactions are advised to specifically notify PJMSettlement that a wire is being sent for such purpose.

B. Virtual Transaction Screening Process

All Virtual Transactions submitted to PJM shall be subject to a credit screen prior to acceptance in the Day-ahead Energy Market auction. The credit screen process will automatically reject Virtual Transactions submitted by the PJM market participant if the participant's Credit Available for Virtual Transactions is exceeded by the **Virtual Credit Exposure** that is calculated based on the participant's submitted Virtual Transactions as described below.

A Participant's Virtual Credit Exposure will be calculated on a daily basis for all Virtual Transactions submitted by the market participant for the next market day using the following equation:

Virtual Credit Exposure = INC and DEC Exposure + Up-to Congestion Exposure
Where:

1) INC and DEC Exposure is calculated as:

(a) ((the total MWh bid or offered, whichever is greater, hourly at each node) x the Nodal Reference Price x 1 day) summed over all nodes and all hours; plus (b) ((the difference between the total bid MWh cleared and total offered MWh cleared hourly at each node) x Nodal Reference Price) summed over all nodes and all hours for the previous cleared Day-ahead Energy Market.

2) Up-to Congestion Exposure is calculated as:

(a) Total MWh bid hourly for each Up-to Congestion Transaction x (price bid – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours; plus (b) Total MWh cleared hourly for each Up-to Congestion Transaction x (cleared price – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours for the previous cleared Day-ahead Energy Market, provided that hours for which the calculation for an Up-to Congestion Transaction is negative, it shall be deemed to have a zero contribution to the sum.

If a Market Participant's Virtual Transactions are rejected as a result of the credit screen process, the Market Participant will be notified via an eMKT error message. A Market Participant whose Virtual Transactions are rejected may alter its Virtual Transactions so that its Virtual Credit Exposure does not exceed its Credit Available forVirtual Transactions, and may resubmit them. Virtual Transactions may be submitted in one or more groups during a day. If one or more groups of Virtual Transactions is submitted and accepted, and a subsequent group of submitted Virtual Transactions causes the total submitted Virtual Transactions to exceed the Virtual Credit Exposure, then only that subsequent set of Virtual Transactions will be rejected. Previously accepted Virtual Transactions will not be affected, though the Market Participant may choose to withdraw them voluntarily.

IV. RELIABILITY PRICING MODEL AUCTION AND PRICE RESPONSIVE DEMAND CREDIT REQUIREMENTS

Settlement during any Delivery Year of cleared positions resulting or expected to result from any Reliability Pricing Model Auction shall be included as appropriate in Peak Market Activity, and the provisions of this Attachment Q shall apply to any such activity and obligations arising therefrom. In addition, the provisions of this section shall apply to any entity seeking to participate in any RPM Auction, to address credit risks unique to such auctions. The provisions of this section also shall apply under certain circumstances to PRD Providers that seek to commit Price Responsive Demand pursuant to the provisions of the Reliability Assurance Agreement.

A. Applicability

A Market Seller seeking to submit a Sell Offer in any Reliability Pricing Model Auction based on any Capacity Resource for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before submitting such Sell Offer. A PRD Provider seeking to commit Price Responsive Demand for which there is a materially increased risk of non-performance must satisfy the credit requirement specified in section IV.B before it may commit the Price Responsive Demand. Credit must be maintained until such risk of non-performance is substantially eliminated, but may be reduced commensurate with the reduction in such risk, as set forth in Section IV.C.

For purposes of this provision, a resource for which there is a materially increased risk of non-performance shall mean: (i) a Planned Generation Capacity Resource; (ii) a Planned Demand Resource or an Energy Efficiency Resource; (iii) a Qualifying Transmission Upgrade; (iv) an existing or Planned Generation Capacity Resource located outside the PJM Region that at the time it is submitted in a Sell Offer has not secured firm transmission service to the border of the

PJM Region sufficient to satisfy the deliverability requirements of the Reliability Assurance Agreement; or (v) Price Responsive Demand to the extent the responsible PRD Provider has not registered PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

B. Reliability Pricing Model Auction and Price Responsive Demand Credit Requirement

Except as provided for Credit-Limited Offers below, for any resource specified in Section IV.A, other than Price Responsive Demand, the credit requirement shall be the RPM Auction Credit Rate, as provided in Section IV.D, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction. For Qualified Transmission Upgrades, the credit requirements shall be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit. However, the credit requirement for Planned Financed Generation Capacity Resources and Planned External Financed Generation Capacity Resources shall be one half of the product of the RPM Auction Credit Rate, as provided in Section IV.D, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction. The RPM Auction Credit Requirement for each Market Seller shall be the sum of the credit requirements for all such resources to be offered by such Market Seller in the auction or, as applicable, cleared by such Market Seller from the relevant auctions. For Price Responsive Demand specified in section IV.A, the credit requirement shall be based on the Nominal PRD Value (stated in Unforced Capacity terms) times the Price Responsive Demand Credit Rate as set forth in section IV.E.

Except for Credit-Limited Offers, the RPM Auction Credit Requirement for a Market Seller will be reduced for any Delivery Year to the extent less than all of such Market Seller's offers clear in the Base Residual Auction or any Incremental Auction for such Delivery Year. Such reduction shall be proportional to the quantity, in megawatts, that failed to clear in such Delivery Year.

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Seller electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement, in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the Auction Credit Rate resulting from section IV.D.b.; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Seller electing this alternative, the RPM Auction Credit Requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-Limited Offer, and the RPM Auction Credit Requirement subsequent to posting of the results will be the Auction Credit Rate, as provided in Section IV.D.b, c. or d., as applicable, times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The availability and operational details of Credit-Limited Offers shall be as described in the PJM Manuals.

As set forth in Section IV.D, a Market Seller's Auction Credit Requirement shall be determined separately for each Delivery Year.

C. Reduction in Credit Requirement

As specified in Section IV.D, the RPM Auction Credit Rate may be reduced under certain circumstances after the auction has closed.

The Price Responsive Demand credit requirement shall be reduced as and to the extent the PRD Provider registers PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Schedule 6.1 of the Reliability Assurance Agreement.

In addition, the RPM Auction Credit Requirement for a Participant for any given Delivery Year shall be reduced periodically, provided the Participant successfully meets progress milestones that reduce the risk of non-performance, as follows:

a. For Planned Demand Resources and Energy Efficiency Resources, the RPM Auction Credit Requirement will be reduced in direct proportion to the megawatts of such Demand Resource that the Resource Provider qualifies as a Capacity Resource, in accordance with the procedures established under the Reliability Assurance Agreement.

b. For Existing Generation Capacity Resources located outside the PJM Region that have not secured sufficient firm transmission to the border of the PJM Region prior to the auction in which such resource is first offered, the RPM Auction Credit Requirement shall be reduced in direct proportion to the megawatts of firm transmission service secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

c. For Planned Generation Capacity Resources located in the PJM Region, the RPM Auction Credit Requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals~~to 50% of the amount calculated under Section IV.B beginning as of the effective date of an Interconnection Service Agreement, and shall be reduced to zero on the date of commencement of Interconnection Service~~.

Milestones	**Increment of reduction from initial RPM Auction Credit Requirement**
Effective Date of Interconnection Service Agreement	50%
Financial Close	15%
Full Notice to Proceed and Commencement of Construction (e.g., footers poured)	5%
Main Power Generating Equipment Delivered	5%

Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit Requirement, except for the Interconnection Service Agreement and Commencement of Interconnection Service milestones, the Capacity Market Seller must submit a sworn, notarized certification of a duly authorized independent engineer in a form acceptable to PJM, certifying that the engineer has personal knowledge, or has engaged in a diligent inquiry to determine, that the milestone has been achieved and that, based on its review of the relevant project information, the independent engineer is not aware of any information that could reasonably cause it to believe that the Capacity Resource will not be in-service by the beginning of the applicable Delivery Year. The Capacity Market Seller shall, if requested by PJM, supply to PJM on a confidential basis all records and documents relating to the independent engineer's certification.

d. For Planned External Generation Capacity Resources ~~located outside the PJM Region~~, the RPM Auction Credit Requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals; provided, however, that the total percentage reduction in the RPM Auction Credit Requirement shall be no greater than the quotient of (a) the MWs of firm transmission service that the Capacity Market Seller has secured for the complete transmission path divided by (b) the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.
~~by 50% once the conditions in both b and c above are met, i.e., the RPM Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B when 1) the equivalent of an Interconnection Service Agreement becomes effective, and 2) 50% or more megawatts of firm transmission service have been secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement. The RPM Credit Requirement for a Planned Generation Capacity Resource located outside the PJM Region shall be reduced to zero when 1) the resource commences Interconnection Service and 2) 100% of the megawatts of firm transmission service have been secured by the Market Seller that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.~~

Credit Reduction Milestones for Planned External Generation Capacity Resources

Milestones	**Increment of reduction from initial RPM Auction Credit Requirement**
Effective Date of the equivalent of an Interconnection Service Agreement	50%
Financial Close	15%
Full Notice to Proceed and Commencement of Construction (e.g., footers poured)	5%
Main Power Generating Equipment Delivered	5%
Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit Requirement, the Capacity Market Seller must demonstrate satisfaction of the applicable milestone in the same manner as set forth for Planned Generation Capacity Resources in subsection (c) above.

e. For Planned Financed Generation Capacity Resources located in the PJM Region, the RPM Auction Credit Requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals.

Credit Reduction Milestones for Planned Financed Generation Capacity Resources	
Milestones	**Increment of reduction from initial RPM Auction Credit Requirement**
Full Notice to Proceed	50%
Commencement of Construction (e.g., footers poured)	15%
Main Power Generating Equipment Delivered	10%
Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit Requirement, the Capacity Market Seller must demonstrate satisfaction of the applicable milestone in the same manner as set forth for Planned Generation Capacity Resources in subsection (c) above.

f. For Planned External Financed Generation Capacity Resources, the RPM Credit Auction Requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals; provided, however, that the total percentage reduction in the RPM Auction Credit Requirement, including the initial 50% reduction for being a Planned External Financed Generation Capacity Resources, shall be no greater than the quotient of (a) the MWs of firm transmission service that the Capacity Market Seller has secured for the complete transmission path divided by (b) the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Credit Reduction Milestones for Planned External Financed Generation Capacity	
Milestones	**Increment of reduction from initial RPM Auction Credit Requirement**
Full Notice to Proceed	50%
Commencement of Construction (e.g., footers poured)	15%
Main Power Generating Equipment Delivered	10%
Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit Requirement, the Capacity Market Seller must demonstrate satisfaction of the applicable milestone in the same manner as set forth for Planned Generation Capacity Resources in subsection (c) above.

~~e~~g. For Qualifying Transmission Upgrades, the RPM Auction Credit Requirement shall be reduced to 50% of the amount calculated under Section IV.B beginning as of the effective date of the latest associated Interconnection Service Agreement (or, when a project will have no such agreement, an Upgrade Construction Service Agreement), and shall be reduced to zero on the date the Qualifying Transmission Upgrade is placed in service. In addition, a Qualifying Transmission Upgrade will be allowed a reduction in its RPM Auction Credit Requirement equal to the amount of collateral currently posted with PJM for the facility construction when the Qualifying Transmission Upgrade meets the following requirements: the Upgrade Construction Service Agreement has been fully executed, the full estimated cost to complete as most recently determined or updated by PJM has been fully paid or collateralized, and all regulatory and other required approvals (except those that must await construction completion) have been obtained. Such reduction in RPM Auction Credit Requirement may not be transferred across different projects.

D. RPM Auction Credit Rate

As set forth in the PJM Manuals, a separate Auction Credit Rate shall be calculated for each Delivery Year prior to each Reliability Pricing Model Auction for such Delivery Year, as follows:

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the greater of ((A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in MW-day or (B) $20 per MW-day) times the number of days in such Delivery Year.

b. Subsequent to the posting of the results from a Base Residual Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (ii) 1.5 times the Net Cost of New

Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).

c. For any resource not previously committed for a Delivery Year that seeks to participate in an Incremental Auction, the Auction Credit Rate shall be:

(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located or (C) $20 per MW-day) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the (greater of (A) 0.5 times Net Cost of New Entry for the PJM Region for such Delivery year or for the Relevant LDA or (B) $20/MW-day) times the number of days in such Delivery Year.

d. Subsequent to the posting of the results of an Incremental Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For Base Capacity Resources: (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of days in such Delivery Year, but no greater than the Auction Credit Rate previously established for such resource's participation in such Incremental Auction pursuant to subsection (c) above) times the number of days in such Delivery Year; and

(ii) For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (i) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (ii) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of days in such Delivery Year).

e. For the purposes of this section IV.D, "Relevant LDA" means the Locational Deliverability Area in which the Capacity Performance Resource is located if a separate Variable Resource Requirement Curve has been established for that Locational Deliverability Area for the Base Residual Auction for such Delivery Year.

E. Price Responsive Demand Credit Rate

a. Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (ii) $20 per MW-day) times the number of days in such Delivery Year;

b. Subsequent to the posting of the results from a Base Residual Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for Price Responsive Demand registered prior to such auction shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the PRD load is located) times the number of days in such Delivery Year times a final price uncertainty factor of 1.05;

c. For any additional Price Responsive Demand that seeks to commit in a Third Incremental Auction in response to a qualifying change in the final LDA load forecast, the Price Responsive Demand Credit Rate shall be the same as the rate for Price Responsive Demand that had cleared in the Base Residual Auction;

d. Subsequent to the posting of the results of the Third Incremental Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for all Price Responsive Demand, shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Final Zonal Capacity Price for the Locational Deliverability Area within which the Price Responsive Demand is located) times the number of days in such Delivery Year, but no greater than the Price Responsive Demand Credit Rate previously established under subsections (a), (b), or (c) of this section for such Delivery Year.

F. RPM Seller Credit - Additional Form of Unsecured Credit for RPM

In addition to the forms of credit specified elsewhere in this Attachment Q, RPM Seller Credit shall be available to Market Sellers, but solely for purposes of satisfying RPM Auction Credit Requirements. If a supplier has a history of being a net seller into PJM markets, on average, over the past 12 months, then PJMSettlement will count as available Unsecured Credit twice the average of that participant’s total net monthly PJMSettlement bills over the past 12 months. This RPM Seller Credit shall be subject to the cap on available Unsecured Credit as established in Section II.F.

G. Credit Responsibility for Traded Planned RPM Capacity Resources

PJMSettlement may require that credit and financial responsibility for planned RPM Capacity Resources that are traded remain with the original party (which for these purposes, means the party bearing credit responsibility for the planned RPM Capacity Resource immediately prior to trade) unless the receiving party independently establishes consistent with the PJM credit policy, that it has sufficient credit with PJMSettlement and agrees by providing written notice to PJMSettlement that it will fully assume the credit responsibility associated with the traded planned RPM Capacity Resource.

V. FINANCIAL TRANSMISSION RIGHT AUCTIONS

A. FTR Credit Limit.

PJMSettlement will establish an FTR Credit Limit for each Participant. Participants must maintain their FTR Credit Limit at a level equal to or greater than their FTR Credit Requirement. FTR Credit Limits will be established only by a Participant providing Financial Security.

B. FTR Credit Requirement.

For each Participant with FTR activity, PJMSettlement shall calculate an FTR Credit Requirement based on FTR cost less a discounted historical value. FTR Credit Requirements shall be further adjusted by ARR credits available and by an amount based on portfolio diversification, if applicable. The requirement will be based on individual monthly exposures which are then used to derive a total requirement.

The FTR Credit Requirement shall be calculated by first adding for each month the FTR Monthly Credit Requirement Contribution for each submitted, accepted, and cleared FTR and then subtracting the prorated value of any ARRs held by the Participant for that month. The resulting twelve monthly subtotals represent the expected value of net payments between PJMSettlement and the Participant for FTR activity each month during the Planning Period. Subject to later adjustment by an amount based on portfolio diversification, if applicable, the FTR Credit Requirement shall be the sum of the individual positive monthly subtotals, representing months in which net payments to PJMSettlement are expected.

C. Rejection of FTR Bids.

Bids submitted into an auction will be rejected if the Participant's FTR Credit Requirement including such submitted bids would exceed the Participant's FTR Credit Limit, or if the Participant fails to establish additional credit as required pursuant to provisions related to portfolio diversification.

D. FTR Credit Collateral Returns.

A Market Participant may request from PJMSettlement the return of any collateral no longer required for the FTR auctions. PJMSettlement is permitted to limit the frequency of such requested collateral returns, provided that collateral returns shall be made by PJMSettlement at least once per calendar quarter, if requested by a Market Participant.

E. Credit Responsibility for Traded FTRs.

PJMSettlement may require that credit responsibility associated with an FTR traded within PJM's eFTR system remain with the original party (which for these purposes, means the party bearing credit responsibility for the FTR immediately prior to trade) unless and until the receiving party independently establishes, consistent with the PJM credit policy, sufficient credit with PJMSettlement and agrees through confirmation of the FTR trade within the eFTR system that it will meet in full the credit requirements associated with the traded FTR.

F. Portfolio Diversification.

Subsequent to calculating a tentative cleared solution for an FTR auction (or auction round), PJM shall both:

1. Determine the FTR Portfolio Auction Value, including the tentative cleared solution. Any Participants with such FTR Portfolio Auction Values that are negative shall be deemed FTR Flow Undiversified.

2. Measure the geographic concentration of the FTR Flow Undiversified portfolios by testing such portfolios using a simulation model including, one at a time, each planned transmission outage or other network change which would substantially affect the network for the specific auction period. A list of such planned outages or changes anticipated to be modeled shall be posted prior to commencement of the auction (or auction round). Any FTR Flow Undiversified portfolio that experiences a net reduction in calculated congestion credits as a result of any one or more of such modeled outages or changes shall be deemed FTR Geographically Undiversified.

For portfolios that are FTR Flow Undiversified but not FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to twice the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For Participants with portfolios that are both FTR Flow Undiversified and FTR Geographically Undiversified, PJMSettlement shall increment the FTR Credit Requirement by an amount equal to three times the absolute value of the FTR Portfolio Auction Value, including the tentative cleared solution. For portfolios that are FTR Flow Undiversified in months subsequent to the current planning year, these incremental amounts, calculated on a monthly basis, shall be reduced (but not below zero) by an amount up to 25% of the monthly value of ARR credits that are held by a Participant. Subsequent to the ARR allocation process preceding an annual FTR auction, such ARRs credits shall be reduced to zero for months associated with that ARR allocation process. PJMSettlement may recalculate such ARR credits at any time, but at a minimum shall do so subsequent to each annual FTR auction. If a reduction in such ARR credits at any time increases the amount of credit required for the Participant beyond its credit available for FTR activity, the Participant must increase its credit to eliminate the shortfall.

If the FTR Credit Requirement for any Participant exceeds its credit available for FTRs as a result of these diversification requirements for the tentatively cleared portfolio of FTRs, PJMSettlement shall immediately issue a demand for additional credit, and such demand must be fulfilled before 4:00 p.m. on the business day following the demand. If any Participant does not timely satisfy such demand, PJMSettlement, in coordination with PJM, shall cause the removal that Participant's entire set of bids for that FTR auction (or auction round) and a new cleared solution shall be calculated for the entire auction (or auction round).

If necessary, PJM shall repeat the auction clearing calculation. PJM shall repeat these portfolio diversification calculations subsequent to any such secondary clearing calculation, and PJMSettlement shall require affected Participants to establish additional credit.

G. FTR Administrative Charge Credit Requirement

In addition to any other credit requirements, PJMSettlement may apply a credit requirement to cover the maximum administrative fees that may be charged to a Participant for its bids and offers.

H. Long-Term FTR Credit Recalculation

Long-term FTR Credit Requirement calculations shall be updated annually for known history, consistent with updating of historical values used for FTR Credit Requirement calculations in the annual auctions.

VI. EXPORT TRANSACTION SCREENING

Export Transactions in the Real-time Energy Market shall be subject to Export Transaction Screening. Export Transaction Screening may be performed either for the duration of the entire Export Transaction, or separately for each time interval comprising an Export Transaction. PJM will deny or curtail all or a portion (based on the relevant time interval) of an Export Transaction if that Export Transaction, or portion thereof, would otherwise cause the Market Participant's Export Credit Exposure to exceed its Credit Available for Export Transactions. Export Transaction Screening shall be applied separately for each Operating Day and shall also be applied to each Export Transaction one or more times prior to the market clearing process for each relevant time interval. Export Transaction Screening shall not apply to transactions established directly by and between PJM and a neighboring Balancing Authority for the purpose of maintaining reliability.

A Market Participant's credit exposure for an individual Export Transaction shall be the MWh volume of the Export Transaction for each relevant time interval multiplied by each relevant Export Transaction Price Factor and summed over all relevant time intervals of the Export Transaction.

VII. FORMS OF FINANCIAL SECURITY

Participants that provide Financial Security must provide the security in a PJMSettlement approved form and amount according to the guidelines below.

Financial Security which is no longer required to be maintained under provisions of the Agreements shall be returned at the request of a participant no later than two Business Days following determination by PJMSettlement within a commercially reasonable period of time that such collateral is not required.

Except when an event of default has occurred, a Participant may substitute an approved PJMSettlement form of Financial Security for another PJMSettlement approved form of Financial Security of equal value. The Participant must provide three (3) Business Days notice to PJMSettlement of its intent to substitute the Financial Security. PJMSettlement will release the replaced Financial Security with interest, if applicable, within (3) Business Days of receiving an approved form of substitute Financial Security.

A. Cash Deposit

Cash provided by a Participant as Financial Security will be held in a depository account by PJMSettlement with interest earned at PJMSettlement's overnight bank rate, and accrued to the Participant. PJMSettlement also may establish an array of investment options among which a Participant may choose to invest its cash deposited as Financial Security. Such investment options shall be comprised of high quality debt instruments, as determined by PJMSettlement, and may include obligations issued by the federal government and/or federal government sponsored enterprises. These investment options will reside in accounts held in PJMSettlement's name in a banking or financial institution acceptable to PJMSettlement. Where practicable, PJMSettlement may establish a means for the Participant to communicate directly with the bank or financial institution to permit the Participant to direct certain activity in the PJMSettlement account in which its Financial Security is held. PJMSettlement will establish and publish procedural rules, identifying the investment options and respective discounts in collateral value that will be taken to reflect any liquidation, market and/or credit risk presented by such investments. PJMSettlement has the right to liquidate all or a portion of the account balances at its discretion to satisfy a Participant's Total Net Obligation to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

B. Letter Of Credit

An unconditional, irrevocable standby letter of credit can be utilized to meet the Financial Security requirement. As stated below, the form, substance, and provider of the letter of credit must all be acceptable to PJMSettlement.

- The letter of credit will only be accepted from U.S.-based financial institutions or U.S. branches of foreign financial institutions ("financial institutions") that have a minimum corporate debt rating of "A" by Standard & Poor's or Fitch Ratings, or "A2" from Moody's Investors Service, or an equivalent short term rating from one of these agencies. PJMSettlement will consider the lowest applicable rating to be the rating of the financial institution. If the rating of a financial institution providing a letter of credit is lowered below A/A2 by any rating agency, then PJMSettlement may require the Participant to provide a letter of credit from another financial institution that is rated A/A2 or better, or to provide a cash deposit. If a letter of credit is provided from a U.S. branch of a foreign institution, the U.S. branch must itself comply with the terms of this credit policy, including having its own acceptable credit rating.

- The letter of credit shall state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety (90) days prior written notice from the issuing financial institution. If PJM or PJMSettlement receives notice from the issuing financial institution that the current letter of credit is being cancelled, the Participant will be required to provide evidence, acceptable to PJMSettlement, that such letter of credit will be replaced with appropriate Financial Security, effective as of the cancellation date of the letter of credit, no later than thirty (30) days before the cancellation date of the letter of credit, and no later than ninety (90) days after the notice of cancellation. Failure to do so will constitute a default under this credit policy and one of more of the Agreements.

- The letter of credit must clearly state the full names of the "Issuer", "Account Party" and "Beneficiary" (PJMSettlement), the dollar amount available for drawings, and shall specify that funds will be disbursed upon presentation of the drawing certificate in accordance with the instructions stated in the letter of credit. The letter of credit should specify any statement that is required to be on the drawing certificate, and any other terms and conditions that apply to such drawings.

- The PJMSettlement Credit Application contains an acceptable form of a letter of credit that should be utilized by a Participant choosing to meet its Financial Security requirement with a letter of credit. If the letter of credit varies in any way from the PJMSettlement format, it must first be reviewed and approved by PJMSettlement. All costs associated with obtaining and maintaining a letter of credit and meeting the policy provisions are the responsibility of the Participant

- PJMSettlement may accept a letter of credit from a Financial Institution that does not meet the credit standards of this policy provided that the letter of credit has third-party support, in a form acceptable to PJMSettlement, from a financial institution that does meet the credit standards of this policy.

VIII. POLICY BREACH AND EVENTS OF DEFAULT

A Participant will have two Business Days from notification of Breach (including late payment notice) or notification of a Collateral Call to remedy the Breach or satisfy the Collateral Call in a manner deemed acceptable by PJMSettlement. Failure to remedy the Breach or satisfy such Collateral Call within such two Business Days will be considered an event of default. If a Participant fails to meet the requirements of this policy but then remedies the Breach or satisfies a Collateral Call within the two Business Day cure period, then the Participant shall be deemed to have complied with the policy. Any such two Business Day cure period will expire at 4:00 p.m. eastern prevailing time on the final day.

Only one cure period shall apply to a single event giving rise to a breach or default. Application of Financial Security towards a non-payment Breach shall not be considered a satisfactory cure of the Breach if the Participant fails to meet all requirements of this policy after such application.

Failure to comply with this policy (except for the responsibility of a Participant to notify PJMSettlement of a Material change) shall be considered an event of default. Pursuant to § 15.1.3(a) of the Operating Agreement of PJM Interconnection, L.L.C. and § I.7.3 of the PJM Open Access Transmission Tariff, non-compliance with the PJMSettlement credit policy is an event of default under those respective Agreements. In event of default under this credit policy or one or more of the Agreements, PJMSettlement, in coordination with PJM, will take such actions as may be required or permitted under the Agreements, including but not limited to the termination of the Participant’s ongoing Transmission Service and participation in PJM Markets. PJMSettlement has the right to liquidate all or a portion of a Participant’s Financial Security at its discretion to satisfy Total Net Obligations to PJMSettlement in the event of default under this credit policy or one or more of the Agreements.

PJMSettlement may hold a defaulting Participant’s Financial Security for as long as such party’s positions exist and consistent with the PJM credit policy in this Attachment Q, in order to protect PJM’s membership from default.

No payments shall be due to a Participant, nor shall any payments be made to a Participant, while the Participant is in default or has been declared in Breach of this policy or the Agreements, or while a Collateral Call is outstanding. PJMSettlement may apply towards an ongoing default any amounts that are held or later become available or due to the defaulting Participant through PJM's markets and systems.

In order to cover Obligations, PJMSettlement may hold a Participant's Financial Security through the end of the billing period which includes the 90th day following the last day a Participant had activity, open positions, or accruing obligations (other than reconciliations and true-ups), and until such Participant has satisfactorily paid any obligations invoiced through such period. Obligations incurred or accrued through such period shall survive any withdrawal from PJM. In event of non-payment, PJMSettlement may apply such Financial Security to such Participant's Obligations, even if Participant had previously announced and effected its withdrawal from PJM.

IX. DEFINITIONS:

All capitalized terms in this Attachment Q that are not otherwise defined herein shall have the same meaning as they are defined in the Agreements.

Affiliate
Affiliate is defined in the PJM Operating Agreement, §1.2.

Agreements
Agreements are the Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, the Reliability Assurance Agreement – West, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Applicant
Applicant is an entity desiring to become a PJM Member, or to take Transmission Service that has submitted the PJMSettlement Credit Application, PJMSettlement Credit Agreement and other required submittals as set forth in this policy.

Breach
Breach is the status of a Participant that does not currently meet the requirements of this policy or other provisions of the Agreements.

Business Day

A Business Day is a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Canadian Guaranty
Canadian Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of this credit policy.

Capacity
Capacity is the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Collateral Call
Collateral Call is a notice to a Participant that additional Financial Security, or possibly early payment, is required in order to remain in, or to regain, compliance with this policy.

Corporate Guaranty
Corporate Guaranty is a legal document used by one entity to guaranty the obligations of another entity.

Credit Available for Export Transactions
Credit Available for Export Transactions is a set-aside of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions
A Market Participant’s Credit Available for Virtual Transactions is the Market Participant’s Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTR, Export Transactions, or other credit requirement determinants as defined in this policy.

Credit-Limited Offer
Credit-Limited Offer shall mean a Sell Offer that is submitted by a Market Seller in an RPM Auction subject to a maximum credit requirement specified by such Market Seller.

Credit Score
Credit Score is a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

Export Credit Exposure
Export Credit Exposure is determined for each Market Participant for a given Operating Day, and is the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price
The Export Nodal Reference Price at each location is the 97th percentile real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction
An Export Transaction is a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transactions Net Activity
Export Transactions Net Activity shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Export Transaction Price Factor
The Export Transaction Price Factor for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening
Export Transaction Screening is the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Financial Close
Financial Close shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the

appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Security
Financial Security is a cash deposit or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Foreign Guaranty
Foreign Guaranty is a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of this credit policy.

FTR Credit Limit
FTR Credit Limit will be equal to the amount of credit established with PJMSettlement that a Participant has specifically designated to PJMSettlement to be set aside and used for FTR activity. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the Participant may have with PJMSettlement.

FTR Credit Requirement
FTR Credit Requirement is the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or is bidding for. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems.

FTR Flow Undiversified
FTR Flow Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Geographically Undiversified
FTR Geographically Undiversified shall have the meaning established in section V.G of this Attachment Q.

FTR Historical Value
FTR Historical Value – For each FTR for each month, this is the historical weighted average value over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year. FTR Historical Values shall be calculated separately for on-peak, off-peak, and 24-hour FTRs for each month of the year. FTR Historical Values shall be adjusted by plus or minus ten percent (10%) for cleared counterflow or normal flow FTRs, respectively, in order to mitigate exposure due to uncertainty and fluctuations in actual FTR value.

FTR Monthly Credit Requirement Contribution
FTR Monthly Credit Requirement Contribution - For each FTR for each month, this is the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month.

For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity
FTR Net Activity shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant
FTR Participant shall mean any Market Participant that is required to provide Financial Security in order to participate in PJM's FTR auctions.

FTR Portfolio Auction Value
FTR Portfolio Auction Value shall mean for each Participant (or Participant account), the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Full Notice to Proceed
Full Notice to Proceed shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Market Participant
Market Participant shall have the meaning provided in the Operating Agreement.

Material
For these purposes, material is defined in §I.B.3, Material Changes. For the purposes herein, the use of the term "material" is not necessarily synonymous with use of the term by governmental agencies and regulatory bodies.

Member
Member shall have the meaning provided in the Operating Agreement.

Minimum Participation Requirements
A set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM markets, as set forth herein and in the Form of Annual Certification set forth as Appendix 1 to this Attachment Q. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Appendix 1 to this Attachment Q.

Net Obligation
Net Obligation is the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services pursuant to the Agreements, after applying a deduction for amounts owed to a

Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position
Net Sell Position is the amount of Net Obligation when Net Obligation is negative.

Nodal Reference Price
The Nodal Reference Price at each location is the 97th percentile price differential between hourly day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. In order to capture seasonality effects and maintain a two-month reference period, reference months will be grouped by two, starting with January (e.g., Jan-Feb, Mar-Apr, … , Jul-Aug, … Nov-Dec). For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

Obligation
Obligation is all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Part II and Part III of the O.A.T.T.), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for Capacity purchases within the PJM Capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Operating Agreement of PJM Interconnection, L.L.C., ("Operating Agreement")
The Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., dated as of June 2, 1997, on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Participant
A Participant is a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer.

Peak Market Activity
Peak Market Activity is a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points, pursuant to provisions of section II.D of this Credit Policy.

Planned Financed Generation Capacity Resource
Planned Financed Generation Capacity Resource shall mean a Planned Generation Capacity Resource that, prior to August 7, 2015, has an effective Interconnection Service Agreement and has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close.

Planned External Financed Generation Capacity Resource

Planned External Financed Generation Capacity Resource shall mean a Planned External Generation Capacity Resource that, prior to August 7, 2015, has an effective agreement that is the equivalent of an Interconnection Service Agreement, has submitted to the Office of the Interconnection the appropriate certification attesting achievement of Financial Close, and has secured at least 50 percent of the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

PJM Markets

The PJM Markets are the PJM Interchange Energy Market and the PJM Capacity markets as established by the Operating Agreement. Also any other markets that exist or may be established in the future wherein Participants may incur Obligations to PJMSettlement.

PJM Open Access Transmission Tariff ("O.A.T.T.")

The Open Access Transmission Tariff of PJM Interconnection, L.L.C., on file with the Federal Energy Regulatory Commission, and as revised from time to time.

Reliability Assurance Agreement ("R.A.A.")

See the definition of the Reliability Assurance Agreement ("R.A.A.") in the Operating Agreement.

RPM Seller Credit

RPM Seller Credit is an additional form of Unsecured Credit defined in section IV of this document.

Seller Credit

A Seller Credit is a form of Unsecured Credit extended to Participants that have a consistent long-term history of selling into PJM Markets, as defined in this document.

Tangible Net Worth

Tangible Net Worth is all assets (not including any intangible assets such as goodwill) less all liabilities. Any such calculation may be reduced by PJMSettlement upon review of the available financial information.

Total Net Obligation

Total Net Obligation is all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position

Total Net Sell Position is all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Transmission Customer

Transmission Customer is a Transmission Customer is an entity taking service under Part II or Part III of the O.A.T.T.

Transmission Service
Transmission Service is any or all of the transmission services provided by PJM pursuant to Part II or Part III of the O.A.T.T.

Uncleared Bid Exposure
Uncleared Bid Exposure is a measure of exposure from Increment Offers and Decrement Bids activity relative to a Participant's established credit as defined in this policy. It is used only as a pre-screen to determine whether a Participant's Increment Offers and Decrement Bids should be subject to Increment Offer and Decrement Bid Screening.

Unsecured Credit
Unsecured Credit is any credit granted by PJMSettlement to a Participant that is not secured by a form of Financial Security.

Unsecured Credit Allowance
Unsecured Credit Allowance is Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Financial Security. See also: "Working Credit Limit."

Up-to Congestion Counterflow Transaction
An Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month
An Up-to Congestion Historical Month is a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction
An Up-to Congestion Transaction will be deemed an Up-to Congestion Prevailing Flow Transaction if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price
The Up-to Congestion Reference Price for an Up-to Congestion Transaction is the specified percentile price differential between source and sink (defined as sink price minus source price) for hourly real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30^{th} percentile
For Up-to Congestion Counterflow Transactions when bid: 20^{th} percentile
For Up-to Congestion Counterflow Transactions when cleared: 5^{th} percentile

Virtual Credit Exposure
Virtual Credit Exposure is the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in this policy.

Virtual Transaction Screening
Virtual Transaction Screening is the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity
Virtual Transactions Net Activity shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Attachment K-Appendix. Virtual Transactions Net Activity may be positive or negative.

Working Credit Limit
Working Credit Limit amount is 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement. The Working Credit Limit establishes the maximum amount of Total Net Obligation that a Market Participant may have outstanding at any time. The calculation of Working Credit Limit shall take into account applicable reductions for Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Working Credit Limit for Virtual Transactions
The Working Credit Limit for Virtual Transactions shall be calculated as 75% of the Market Participant's Unsecured Credit Allowance and/or 75% of the Financial Security provided by the Market Participant to PJMSettlement when the Market Participant is at or below its Peak Market Activity credit requirements as specified in section II.D of this Credit Policy. When the Market Participant provides additional Unsecured Credit Allowance and/or Financial Security in excess of its Peak Market Activity credit requirements, such additional Unsecured Credit Allowance and/or Financial Security shall not be discounted by 25% when calculating the Working Credit Limit for Virtual Transactions. The Working Credit Limit for Virtual Transactions is a component in the calculation of Credit Available for Virtual Transactions. The calculation of Working Credit Limit for Virtual Transactions shall take into account applicable reductions for Minimum Participation Requirements, FTR, or other credit requirement determinants as defined in this policy.

Appendix 1 to Attachment Q

PJM MINIMUM PARTICIPATION CRITERIA
OFFICER CERTIFICATION FORM

Participant Name: ____ ("Participant")

I, ____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. and PJM Settlement, Inc. (”PJMSettlement”) are relying on this certification as evidence that Participant meets the minimum requirements set forth in Attachment Q to the PJM Open Access Transmission Tariff ("PJM Tariff"), hereby certify that I have full authority to represent on behalf of Participant and further represent as follows, as evidenced by my initialing each representation in the space provided below:

1. All employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Amended and Restated Operating Agreement ("PJM Operating Agreement") on behalf of the Participant have received appropriate[1] training and are authorized to transact on behalf of Participant._________

2. Participant has written risk management policies, procedures, and controls, approved by Participant's independent risk management function[2] and applicable to transactions in the PJM markets in which it participates and for which employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Operating Agreement have been trained, that provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Participant is exposed, including, but not limited to credit risks, liquidity risks and market risks.__________

3. An FTR Participant (as defined in Attachment Q to the PJM Tariff) must make either the following 3.a. or 3.b. additional representations, evidenced by the undersigned officer initialing either the one 3.a. representation or the six 3.b. representations in the spaces provided below:

   3.a. Participant transacts in PJM's FTR markets with the sole intent to hedge congestion risk in connection with either obligations Participant has to serve load or rights Participant has to generate electricity in the PJM Region ("physical

[1] As used in this representation, the term "appropriate" as used with respect to training means training that is (i) comparable to generally accepted practices in the energy trading industry, and (ii) commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the participant.
[2] As used in this representation, a Participant's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Participant's trading functions, such as a risk management committee, a risk officer, a Participant's board or board committee, or a board or committee of the Participant's parent company.

transactions") and monitors all of the Participant's FTR market activity to endeavor to ensure that its FTR positions, considering both the size and pathways of the positions, are either generally proportionate to or generally do not exceed the Participant's physical transactions, and remain generally consistent with the Participant's intention to hedge its physical transactions.__________

3.b. On no less than a weekly basis, Participant values its FTR positions and engages in a probabilistic assessment of the hypothetical risk of such positions using analytically based methodologies, predicated on the use of industry accepted valuation methodologies.__________

Such valuation and risk assessment functions are performed either by persons within Participant's organization independent from those trading in PJM's FTR markets or by an outside firm qualified and with expertise in this area of risk management.__________

Having valued its FTR positions and quantified their hypothetical risks, Participant applies its written policies, procedures and controls to limit its risks using industry recognized practices, such as value-at-risk limitations, concentration limits, or other controls designed to prevent Participant from purposefully or unintentionally taking on risk that is not commensurate or proportional to Participant's financial capability to manage such risk.__________

Exceptions to Participant's written risk policies, procedures and controls applicable to Participant's FTR positions are documented and explain a reasoned basis for the granting of any exception.__________

Participant has provided to PJMSettlement, in accordance with Section I A. of Attachment Q to the PJM Tariff, a copy of its current governing risk management policies, procedures and controls applicable to its FTR trading activities.__________

If the risk management policies, procedures and controls applicable to Participant's FTR trading activities submitted to PJMSettlement were submitted prior to the current certification, Particpant certifies that no substantive changes have been made to such policies, procedures and controls applicable to its FTR trading activities since such submission.__________

4. Participant has appropriate personnel resources, operating procedures and technical abilities to promptly and effectively respond to all PJM communications and directions.__________

5. Participant has demonstrated compliance with the Minimum Capitalization criteria set forth in Attachment Q of the PJM Open Access Transmission Tariff that are applicable to the PJM market(s) in which Participant transacts, and is not aware of any change having occurred or being imminent that would invalidate such compliance.__________

6. All Participants must certify and initial in at least one of the four sections below:

   a. I certify that Participant qualifies as an "appropriate person" as that term is defined under Section 4(c)(3), or successor provision, of the Commodity Exchange Act or an "eligible contract participant" as that term is defined under Section 1a(18), or successor provision, of the Commodity Exchange Act. I certify that Participant will cease transacting in PJM's Markets and notify PJMSettlement immediately if Participant no longer qualifies as an "appropriate person" or "eligible contract participant."__________

      If providing financial statements to support Participant's certification of qualification as an "appropriate person:"

      I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $5 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

      If providing financial statements to support Participant's certification of qualification as an "eligible contract participant:"

      I certify, to the best of my knowledge and belief, that the financial statements provided to PJMSettlement present fairly, pursuant to such disclosures in such financial statements, the financial position of Participant as of the date of those financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $10 million total asset levels reflected in these financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

   b. I certify that Participant has provided an unlimited Corporate Guaranty in a form acceptable to PJM as described in Section I.C of Attachment Q from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant per Participant for which the issuer has issued an unlimited Corporate Guaranty. I certify that Participant will cease transacting PJM's Markets and notify PJMSettlement immediately if issuer of the unlimited Corporate Guaranty for Participant no longer has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty.__________

I certify that the issuer of the unlimited Corporate Guaranty to Participant continues to have at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty. I acknowledge that PJM and PJMSettlement are relying upon my certifications to maintain compliance with federal regulatory requirements.__________

c. I certify that Participant fulfills the eligibility requirements of the Commodity Futures Trading Commission exemption order (78 F.R. 19880 – April 2, 2013) by being in the business of at least one of the following in the PJM Region as indicated below (initial those applicable):

1. Generating electric energy, including Participants that resell physical energy acquired from an entity generating electric energy:__________

2. Transmitting electric energy:__________

3. Distributing electric energy delivered under Point-to-Point or Network Integration Transmission Service, including scheduled import, export and wheel through transactions:__________

4. Other electric energy services that are necessary to support the reliable operation of the transmission system:__________

Description only if c(4) is initialed:

____

Further, I certify that Participant will cease transacting in PJM's Markets and notify PJMSettlement immediately if Participant no longer performs at least one of the functions noted above in the PJM Region. I acknowledge that PJM and PJMSettlement are relying on my certification to maintain compliance with federal energy regulatory requirements.__________

d. I certify that Participant has provided a letter of credit of $5 million or more to PJMSettlement in a form acceptable to PJMSettlement as described in Section VI.B of Attachment Q that the Participant acknowledges cannot be utilized to meet its credit requirements to PJMSettlement. I acknowledge that PJM and PJMSettlement are relying on the provision of this letter of credit and my certification to maintain compliance with federal regulatory requirements.__________

7. I acknowledge that I have read and understood the provisions of Attachment Q of the PJM Tariff applicable to Participant's business in the PJM markets, including those provisions describing PJM's minimum participation requirements and the enforcement actions available to PJMSettlement of a Participant not satisfying those requirements. I acknowledge that the information provided herein is true and accurate to the best of my belief and knowledge after due investigation. In addition, by signing this Certification, I

acknowledge the potential consequences of making incomplete or false statements in this Certification.___________

Date: ______________________________ ____________________________________

(Signature)

Print Name: ____________________________________

Title: ____________________________________

OATT ATT DD.2

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ER15-806-000: Version 20.0.2, Filed 12/31/2014, Effective 03/02/2015

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ER15-623-004: Version 21.1.0, Filed 07/09/2015, Effective 04/01/2015

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the Operating Agreement or RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1~~A~~ Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1A Annual Energy Efficiency Resource

"Annual Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.2A Base Capacity Demand Resource

"Base Capacity Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.2B Base Capacity Demand Resource Constraint

"Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.2C Base Capacity Demand Resource Price Decrement

"Base Capacity Demand Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

2.2D Base Capacity Energy Efficiency Resource

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.2E Base Capacity Resource

“Base Capacity Resource” shall mean a Capacity Resource as described in section 5.5A(b).

2.2F Base Capacity Resource Constraint

“Base Capacity Resource Reliability Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.2G Base Capacity Resource Price Decrement

"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.6A Compliance Aggregation Area (CAA)

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the

2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in section 6.6(g).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.11A Capacity Performance Resource

“Capacity Performance Resource” shall mean a Capacity Resource as described in section 5.5A(a).

2.11B Capacity Performance Transition Incremental Auction

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in section 5.14D.

2.12 Capacity Resource

“Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

“Capacity Resource Clearing Price” shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.13A Capacity Storage Resource

“Capacity Storage Resource” shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

2.14 Capacity Transfer Right

“Capacity Transfer Right” shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

“Conditional Incremental Auction” shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

“CONE Area” shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor or DR Factor

"Demand Resource Factor" or "DR Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 [Reserved for Future Use]

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.23A Emergency Action

"Emergency Action" shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage

Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Sub-Annual Resource Reliability Target

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 Delivery Year~~s beginning June 1, 2017~~. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for ~~such~~the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 Generator Forced Outage

"Generator Forced Outage" shall have the meaning specified in the Operating Agreement.

2.33 Generator Maintenance Outage

"Generator Maintenance Outage" shall have the meaning specified in the Operating Agreement.

2.33A Generator Planned Outage

"Generator Planned Outage" shall have the meaning specified in the Operating Agreement.

~~2.32 [Reserved]~~

~~2.33 [Reserved]~~

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd~~D~~ increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Intermittent Resource

“Intermittent Resource” shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources. ~~**[Reserved]**~~

2.36A Limited Demand Resource

“Limited Demand Resource**”** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

“Limited Demand Resource Reliability Target**”** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 Delivery Year~~s beginning June 1, 2017~~ for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016~~-~~/2017 and ~~subsequent~~2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool

Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for ~~such~~the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year ~~commencing June 1, 2017 and subsequent Delivery Years~~, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO

Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-

Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.48A Performance Assessment Hour

"Performance Assessment Hour" shall mean each whole or partial clock-hour for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Hours for a Base Capacity Resource shall not include any hours outside the calendar months of June through September.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

2.60A Repowered / Repowering

"Repowering" or "Repowered" shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual

Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65B.01 Small Commercial Customer

"Small Commercial Customer," as used in Schedule 6 of the RAA and Attachment DD-1 of the Tariff, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year ~~commencing June 1, 2017 and subsequent Delivery Years~~, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-

Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect ~~the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and~~ any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year *and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C of this Attachment DD.*

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year *and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C of this attachment DD.*

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.6A Compliance Aggregation Area (CAA)

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of Annual Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in section 6.6(g).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8, or, as to an FRR entity, in Schedule 8.1 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5, or pursuant to an FRR Capacity Plan.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" (or "DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

2.22 [Reserved for Future Use]

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Sub-Annual Resource Reliability Target

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for Delivery Years beginning June 1, 2017. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

"Sub-Annual Resource Constraint" shall mean, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 [Reserved]

2.33 [Reserved]

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 [Reserved]

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for Delivery Years beginning June 1, 2017 for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016-2017 and subsequent Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

"Limited Resource Constraint" shall mean, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

“Minimum Extended Summer Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

“Nominated Demand Resource Value” shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

“Nominated Energy Efficiency Value” shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the ~~Reliability Assurance Agreement~~Operating Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the

Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.60A Repowered / Repowering

"Repowering" or "Repowered" shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65B.01 Small Commercial Customer

"Small Commercial Customer," as used in Schedule 6 of the RAA and Attachment DD-1 of the Tariff, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C of this Attachment DD.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C of this attachment DD.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the *Operating Agreement or* RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1 Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1A Annual Energy Efficiency Resource

"Annual Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an *Annual* Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.2A Base Capacity Demand Resource

"Base Capacity Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.2B Base Capacity Demand Resource Constraint

"Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.2C Base Capacity Demand Resource Price Decrement

"Base Capacity Demand Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

2.2D Base Capacity Energy Efficiency Resource

"Base Capacity Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.2E Base Capacity Resource

"Base Capacity Resource" shall mean a Capacity Resource as described in section 5.5A(b).

2.2F Base Capacity Resource Constraint

"Base Capacity Resource Reliability Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].
"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the

clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.2G Base Capacity Resource Price Decrement

"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.6A Compliance Aggregation Area (CAA)

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, *for Delivery Years through May 31, 2018,* Annual Resources *and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources,* the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in section 6.6(g).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.11A Capacity Performance Resource

“Capacity Performance Resource” shall mean a Capacity Resource as described in section 5.5A(a).

2.11B Capacity Performance Transition Incremental Auction

“Capacity Performance Transition Incremental Auction” shall have the meaning specified in section 5.14D.

2.12 Capacity Resource

“Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

“Capacity Resource Clearing Price” shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.13A Capacity Storage Resource

“Capacity Storage Resource” shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

2.14 Capacity Transfer Right

“Capacity Transfer Right” shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

“Conditional Incremental Auction” shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

“CONE Area” shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 , or, as to an FRR entity, in Schedule 8.1of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5, or pursuant to an FRR Capacity Plan.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor *or DR Factor*

"Demand Resource Factor" *or "DR Factor"* shall have the meaning specified in the Reliability Assurance Agreement.

2.22 [Reserved for Future Use]

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.23A Emergency Action

"Emergency Action" shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean, *for Delivery Years through May 31, 2018*, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Sub-Annual Resource Reliability Target

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for *the 2017/2018* Delivery Year. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

"Sub-Annual Resource Constraint" shall mean, *for the 2017/2018 Delivery Year*, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for *the 2017/2018* Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 Generator Forced Outage

"Generator Forced Outage" shall have the meaning specified in the Operating Agreement.

2.33 Generator Maintenance Outage

“Generator Maintenance Outage” shall have the meaning specified in the Operating Agreement.

2.33A Generator Planned Outage

“Generator Planned Outage” shall have the meaning specified in the Operating Agreement.

2.34 Incremental Auction

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFOR*d* increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

“Incremental Capacity Transfer Right” shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 *Intermittent Resource*

“Intermittent Resource” shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

2.36A Limited Demand Resource

“Limited Demand Resource**”** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

“Limited Demand Resource Reliability Target**”** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for *the 2017/2018* Delivery Year for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and *2017/2018* Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

“Limited Resource Constraint” shall mean, *for the 2017/2018 Delivery Year*, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for *the 2017/2018* Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the *2017/2018* Delivery Year , a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

“Nominated Demand Resource Value” shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

“Nominated Energy Efficiency Value” shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

“Opportunity Cost” shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

“Peak-Hour Dispatch” shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.48A Performance Assessment Hour

"Performance Assessment Hour" shall mean each whole or partial clock-hour for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Hours for a Base Capacity Resource shall not include any hours outside the calendar months of June through September.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Operating Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, *or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction*.

2.60A Repowered / Repowering

"Repowering" or "Repowered" shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, *for Delivery Years through May 31, 2018,* as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean, *for Delivery Years through May 31, 2018*: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65B.01 Small Commercial Customer

"Small Commercial Customer," as used in Schedule 6 of the RAA and Attachment DD-1 of the Tariff, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the *2017/2018* Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction*, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.*

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C and 5.14E of this Attachment DD.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C and 5.14E of this attachment DD.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the Operating Agreement or RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1 Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1A Annual Energy Efficiency Resource

"Annual Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.2.01 Balancing Ratio

"Balancing Ratio" shall have the meaning provided in section 10A.

2.2A Base Capacity Demand Resource

"Base Capacity Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.2B Base Capacity Demand Resource Constraint

"Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.2C Base Capacity Demand Resource Price Decrement

"Base Capacity Demand Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

2.2D Base Capacity Energy Efficiency Resource

"Base Capacity Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.2E Base Capacity Resource

"Base Capacity Resource" shall mean a Capacity Resource as described in section 5.5A(b).

2.2F Base Capacity Resource Constraint

"Base Capacity Resource Reliability Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA

and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].
"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.2G Base Capacity Resource Price Decrement

"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.6A Compliance Aggregation Area (CAA)

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in section 6.6(g).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.11A Capacity Performance Resource

"Capacity Performance Resource" shall mean a Capacity Resource as described in section 5.5A(a).

2.11B Capacity Performance Transition Incremental Auction

"Capacity Performance Transition Incremental Auction" shall have the meaning specified in section 5.14D.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.13A Capacity Storage Resource

"Capacity Storage Resource" shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8, or, as to an FRR entity, in Schedule 8.1 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5, or pursuant to an FRR Capacity Plan.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor or DR Factor

"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

2.22 [Reserved for Future Use]

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.23A Emergency Action

"Emergency Action" shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24.01 Environmentally-Limited Resource

"Environmentally-Limited Resource" shall mean a resource which 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 by a governmental authority to operating only during declared PJM capacity emergencies.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Sub-Annual Resource Reliability Target

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 Generator Forced Outage

"Generator Forced Outage" shall have the meaning specified in the Operating Agreement.

2.33 Generator Maintenance Outage

"Generator Maintenance Outage" shall have the meaning specified in the Operating Agreement.

2.33A Generator Planned Outage

"Generator Planned Outage" shall have the meaning specified in the Operating Agreement.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Intermittent Resource

"Intermittent Resource" shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year , a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.48A Performance Assessment Hour

"Performance Assessment Hour" shall mean each whole or partial clock-hour for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Hours for a Base Capacity Resource shall not include any hours outside the calendar months of June through September.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Operating Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

2.60A Repowered / Repowering

"Repowering" or "Repowered" shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65B.01 Small Commercial Customer

"Small Commercial Customer," as used in Schedule 6 of the RAA and Attachment DD-1 of the Tariff, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C of this Attachment DD.

2.69C Updated VRR Curve Decrement

“Updated VRR Curve Decrement” shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by the reduction in Unforced Capacity commitments associated with the transition provision of section 5.14C of this attachment DD.

2.70 Variable Resource Requirement Curve

“Variable Resource Requirement Curve” shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

“Zonal Capacity Price” shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

OATT ATT DD.5.12

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5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; ~~and~~ for the 2017/2018 Delivery Year ~~commencing June 1, 2017 and subsequent Delivery Years~~, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;
- For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;~~.~~
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total

Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the Delivery years through May 31, 2018, ~~T~~the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;

- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;

- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- For the Delivery Years through May 31, 2018, ~~F~~for each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement

- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; ~~and~~ for the 2017/2018 Delivery Year~~ commencing June 1, 2017 and subsequent Delivery Years~~, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and

- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(2) of this Attachment, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(1) of this Attachment, and the conditions stated in section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) ~~the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B)~~ the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B~~C~~) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C~~D~~) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D~~E~~) the reduction in Unforced Capacity commitments associated with the transition *provisions* of sections 5.14B and *5.14C* of this Attachment DD. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by section 5.4(c)(3)(i) of this Attachment, the Office of the Interconnection first shall determine the total quantity of (A) ~~the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B)~~ the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B~~C~~) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C~~D~~) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by section 5.4(c)(3)(ii) of this Attachment, plus (D~~E~~) the reduction in Unforced Capacity commitments associated with the transition *provisions* of sections 5.14B and *5.14C* of this Attachment DD; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) ~~the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B)~~ the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B~~C~~) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. For the Delivery Years through May 31, 2018, i~~I~~f more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

(A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and

- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; for the *2017/2018* Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; *and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;*
- *For the Delivery Years through May 31, 2018,* the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement*.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of

Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- *For the Delivery years through May 31, 2018, t*he PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;

- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;*

- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;

- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- *For the Delivery Years through May 31, 2018, f*or each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;

- *For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement*

- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the *2017/2018* Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; *and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;*

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and

- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(2) of this Attachment, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(1) of this Attachment, and the conditions stated in section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction,* minus (*B*) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (*C*) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (*D*) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, ~~and~~ 5.14C and 5.14E of this Attachment DD. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated

VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by section 5.4(c)(3)(i) of this Attachment, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction,* minus (*B*) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (*C*) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by section 5.4(c)(3)(ii) of this Attachment, plus (*D*) the reduction in Unforced Capacity commitments associated with the transition provisions of sections 5.14B, ~~and~~ 5.14C and 5.14E of this Attachment DD; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, *plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction,* minus (*B*) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. *For the Delivery Years through May 31, 2018, i*f more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits (“Excess Commitment Credits”) under certain circumstances as follows:

(A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

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5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, ~~and~~ Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the

Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-

block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, 5.14B, 5.14C, 5.14D, and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) *General Rule.* Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, *or a Unit-Specific Exception* with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) *Applicability.* A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including *R*epowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle *technology*) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 *or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction*; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility *(as defined in Part 292 of FERC's regulations)*, where the Capacity Market Seller is *the* owner of the Qualifying Facility *or has contracted for the Unforced Capacity of such facility* and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) *MOPR Floor Offer Price.* The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the *2018/2019* Delivery Year *and subsequent Delivery Years,* the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), a combined cycle generator ("CC"), and an integrated gasification combined cycle generator ("IGCC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. *For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year.* The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT $/MW-yr	*132,200*	*130,300*	*128,900*	*130,300*
CC $/MW-yr	*185,700*	*176,000*	*172,600*	*179,400*
IGCC $/MW-yr	582,042	558,486	547,240	537,306

i) Commencing with the Delivery Year that begins on June 1, *2019,* the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, *that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further* that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above,

except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3,198 per MW-year.

(4) *Duration*. The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until *(and including)* the *first Delivery Year for* which *a* Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) *Effect of Exemption or Exception*. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). *To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process*. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption *or exception* and cleared the RPM Auction for which it obtained such exemption *or exception* shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(*10*) hereof.

(6) ***Self-Supply Exemption.*** A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a *Vertically Integrated U*tility and the MOPR Screened Generation Resource is planned

consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE's Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW

Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE's future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long *positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.*

v*i*) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vi*i*) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of

the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. *Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak.* Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) *Competitive Entry Exemption*. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs *of the MOPR Screened Generation Resource* are recovered from customers either directly or indirectly through a non-bypassable charge*, except in the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.*

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be "Competitive and Non-Discriminatory" only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity

Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, *over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.*

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(*9*) <u>Exemption/Exception Process</u>.

i) *The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.*

ii) The Capacity Market Seller must submit its request for a *Unit-Specific Exception,* Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption *or exception* that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption *or exception* criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller

shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

*i*ii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption *or exception* request. The Office of the Interconnection shall also review all exemption a*nd exception* requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption *or exception* request. The Office of the Interconnection shall reject a requested exemption *or exception* if the Capacity Market Seller*'s request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request.* If the Office of the Interconnection does not provide its determination *on an exemption or exception request* by no later than sixty-five (65) days after receipt of the exemption *or exception* request, the request shall be deemed granted. *Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (5) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request.* A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(*10*) *Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.*

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared

in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(*10*) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference

specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This *t*ransition *p*rovision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, "Transition Delivery Years" and each a "Transition Delivery Year") by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a "Qualified DR Provider."

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission's order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this *section 5.14A*. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this *section 5.14A* to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

    DRTC = (IAP – BRP) * DRMW

    Where:

    DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

    IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

    BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

    DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this *section 5.14A*, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

   a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

   b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

   c. an aggregate amount that exceeds:

      (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

      (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

      (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this *section 5.14A* shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this *section 5.14A*, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and

received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This *t*ransition *p*rovision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORd value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORd value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test

procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as “Applicable Delivery Years” and each an “Applicable Delivery Year”) that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an “Affected Demand Resource” and an “Affected Curtailment Service Provider,” respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the Affected Demand Resource, of the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year, by type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR) and by Zone or sub-Zone, by the applicable deadline as follows:

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;

- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Generation Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, *Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements,* all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the

Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-

block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, 5.14B, 5.14C, *5.14D*, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) General Rule. Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, *or a* Unit-Specific Exception with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) Applicability. A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including Repowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle technology) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility (as defined in Part 292 of FERC's regulations), where the Capacity Market Seller is the owner of the Qualifying Facility or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) MOPR Floor Offer Price. The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), a combined cycle generator ("CC"), and an integrated gasification combined cycle generator ("IGCC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT $/MW-yr	132,200	130,300	128,900	130,300
CC $/MW-yr	185,700	176,000	172,600	179,400
IGCC $/MW-yr	582,042	558,486	547,240	537,306

i) Commencing with the Delivery Year that begins on June 1, 2019, the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above,

except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3,198 per MW-year.

(4) Duration. The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until (and including) the first Delivery Year for which a Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) Effect of Exemption or Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption or exception and cleared the RPM Auction for which it obtained such exemption or exception shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(*10*) hereof.

(6) Self-Supply Exemption**.** A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated *U*tility and the MOPR Screened Generation Resource is planned

consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE's Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW

Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE’s Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region (“Net Long”), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE’s Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE’s future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long

positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

v*i*) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vi*i*) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of

the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak. Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) Competitive Entry Exemption. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs of the MOPR Screened Generation Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be "Competitive and Non-Discriminatory" only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity

Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period

identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(*9*) Exemption/Exception Process.

i) The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.

ii) The Capacity Market Seller must submit its request for a Unit-Specific Exception, Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption or exception that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption or exception criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller

shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

iii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption or exception request. The Office of the Interconnection shall also review all exemption and exception requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption or exception request. The Office of the Interconnection shall reject a requested exemption or exception if the Capacity Market Seller's request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request. If the Office of the Interconnection does not provide its determination on an exemption or exception request by no later than sixty-five (65) days after receipt of the exemption or exception request, the request shall be deemed granted. Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (5) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(10) <u>Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.</u>

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared

in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(10) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference

specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This transition provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, “Transition Delivery Years” and each a “Transition Delivery Year”) by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a “Qualified DR Provider.”

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission’s order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the

identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this section 5.14A. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this section 5.14A to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

   DRTC = (IAP – BRP) * DRMW

   Where:

   DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

   IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

   BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

   DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this section 5.14A, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

   a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

   b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

   c. an aggregate amount that exceeds:

      (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

      (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

      (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this section 5.14A shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this section 5.14A, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and

received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORd value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORd value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test

procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell

megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- *the target quantities of Capacity Performance Resources specified below;*
- *the Sell Offers submitted in such auction.*

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Generation Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the endues customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, “non-viable megawatts”), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental

Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the

Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-

block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, 5.14B, 5.14C, 5.14D, and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) General Rule. Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, or a Unit-Specific Exception with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) Applicability. A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including *R*epowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle technology) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility (as defined in Part 292 of FERC's regulations), where the Capacity Market Seller is the owner of the Qualifying Facility or has contracted for the Unforced Capacity of such facility and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) MOPR Floor Offer Price. The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), a combined cycle generator ("CC"), and an integrated gasification combined cycle generator ("IGCC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT $/MW-yr	132,200	130,300	128,900	130,300
CC $/MW-yr	185,700	176,000	172,600	179,400
IGCC $/MW-yr	582,042	558,486	547,240	537,306

i) Commencing with the Delivery Year that begins on June 1, 2019, the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above,

except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3,198 per MW-year.

(4) Duration. The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until (and including) the first Delivery Year for which a Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) Effect of Exemption or Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption or exception and cleared the RPM Auction for which it obtained such exemption or exception shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(*10*) hereof.

(6) Self-Supply Exemption**.** A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a Vertically Integrated *U*tility and the MOPR Screened Generation Resource is planned

consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE's Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW

Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE's future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long

positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

v*i*) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vi*i*) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of

the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak. Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) Competitive Entry Exemption. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs of the MOPR Screened Generation Resource are recovered from customers either directly or indirectly through a non-bypassable charge, except in the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be "Competitive and Non-Discriminatory" only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity

Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period

identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(9) <u>Exemption/Exception Process</u>.

i) The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.

ii) The Capacity Market Seller must submit its request for a Unit-Specific Exception, Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption or exception that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption or exception criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller

shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

iii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption or exception request. The Office of the Interconnection shall also review all exemption and exception requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption or exception request. The Office of the Interconnection shall reject a requested exemption or exception if the Capacity Market Seller's request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request. If the Office of the Interconnection does not provide its determination on an exemption or exception request by no later than sixty-five (65) days after receipt of the exemption or exception request, the request shall be deemed granted. Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (5) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(10) <u>Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.</u>

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared

in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(*10*) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference

specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This transition provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, "Transition Delivery Years" and each a "Transition Delivery Year") by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a "Qualified DR Provider."

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission's order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the

identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this section 5.14A. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this section 5.14A to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

   DRTC = (IAP – BRP) * DRMW

   Where:

   DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

   IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

   BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

   DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this section 5.14A, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

   a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

   b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

   c. an aggregate amount that exceeds:

      (i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

      (ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

      (iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this section 5.14A shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this section 5.14A, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and

received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This *t*ransition *p*rovision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORd value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORd value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test

procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

2. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment

Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery

Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;

- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any ~~Generation~~ Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity

Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

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ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Direct Load Control, as further specified in section G and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance

with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- if applicable, Direct Load Control (DLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, the product of the Nominated Value of the Demand Resource times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four~~three~~ ways:

Direct Load Control (DLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for DLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other

ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

The Nominated Value for a Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

For Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance for Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for GLD, and will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(iii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered DLC programs. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and DLC programs to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2012. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.~~, which~~

- For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

• For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;~~.~~ and

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

• For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, t~~T~~he Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by

no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, *a Base Capacity Demand Resource*, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance

with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand

response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights

and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, the product of the Nominated Value of the Demand Resource times the DR Factor, times the Forecast Pool Requirement*, and for the 2018/2019 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement*. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following *four* ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).

DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, ~~T~~the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, ~~LSE contact information,~~ number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, ~~F~~for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Prior to June 1, 2016, ~~C~~compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for ~~FSL~~Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

(PLC) - (Load *LF)

Compliance is checked on an individual customer basis for ~~GLD~~Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance~~, and~~ will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii~~i~~) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30 minutes of the clock hour (i.e., “partial dispatch compliance hour”). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer’s Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak *summer and winter* periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2012. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process

intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- *For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;*
- *For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource* shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; *and*

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.*

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. *For Delivery Years through May 31, 2018, t*he Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. *For the 2018/2019 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.*

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected

life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Direct Load Control, as further specified in section G and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance

with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- if applicable, Direct Load Control (DLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider’s maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;
- the Demand Resource Provider’s maximum for any single Delivery Year of [such provider’s cleared Demand Resource quantity] plus [such provider’s quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and
- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider’s rights and obligations thereunder, including the Demand Resource Provider’s ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four ways:

Direct Load Control (DLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for DLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- Supplemental status reports, detailing Demand Resources available, as requested by PJM;
- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other

ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

The Nominated Value for a Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

For Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance for Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for GLD, and will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(iii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered DLC programs. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and DLC programs to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2012. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance

with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand

response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;
- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and
- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights

and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine

reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office

of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events for all Demand Resources not committed as a Capacity Performance Resource occurring through ~~the~~ May 31, 2018, and for Load Management Events for Demand Resources committed as a Base Capacity Resource or a Capacity Performance Resource occurring during the months of June through September ~~of the 2018/2019 Delivery Year and subsequent Delivery Years~~:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event~~,~~, for each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events for Demand Resources committed as a Base Capacity Resource or as a Capacity Performance Resource occurring during the months of October through May~~ of the 2018/2019 Delivery Year and subsequent Delivery Years~~:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of Schedule 1 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2012. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an

Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

OA Definitions C-D

EL15-29-000: Version 4.0.0, Filed 12/12/2014, Effective 04/01/2015

ER15-1849-000: Version 8.0.0, Filed 06/03/2015, Effective 08/03/2015

Definitions C - D

1.6 Capacity Resource.

"Capacity Resource" have the meaning provided in the Reliability Assurance Agreement.

1.6.01 Catastrophic Force Majeure.

"Catastrophic Force Majeure" shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection's determination is subject to review by the Commission.

1.6A Consolidated Transmission Owners Agreement.

"Consolidated Transmission Owners Agreement" dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

1.7 Control Area.

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7.01 Control Zone.

"Control Zone" shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

1.7.01a Counterparty.

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with Market Participants or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7.02 Default Allocation Assessment.

"Default Allocation Assessment" shall mean the assessment determined pursuant to section 15.2.2 of this Agreement.

1.7.03 Demand Resource.

"Demand Resource" shall have the meaning provided in the Reliability Assurance Agreement.

1.7A Designated Entity.

An entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Section 1.5.8 of Schedule 6 of this Agreement.

1.7B [Reserved].

Definitions C - D

1.6 Capacity Resource.

"Capacity Resource" have the meaning provided in the Reliability Assurance Agreement.

1.6.01 Catastrophic Force Majeure.

"Catastrophic Force Majeure" shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection's determination is subject to review by the Commission.

1.6A Consolidated Transmission Owners Agreement.

"Consolidated Transmission Owners Agreement" dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C.

1.7 Control Area.

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7.01 Control Zone.

"Control Zone" shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

1.7.01a Counterparty.

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with Market Participants or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and this Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Market Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection.

1.7.02 Default Allocation Assessment.

"Default Allocation Assessment" shall mean the assessment determined pursuant to section 15.2.2 of this Agreement.

1.7.03 Demand Resource.

"Demand Resource" shall have the meaning provided in the Reliability Assurance Agreement.

1.7A Designated Entity.

An entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Section 1.5.8 of Schedule 6 of this Agreement.

1.7A.01 Direct Load Control:

Load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

1.7B [Reserved].

OA Schedule 1 Section 1.3

EL15-29-000: Version 21.0.0, Filed 12/12/2014, Effective 04/01/2015

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1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.01A Cold Weather Alert.

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.02A Coordinated External Transaction.

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.02B Coordinated Transaction Scheduling.

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Section 1.13 of Schedule 1 of this Agreement.

1.3.1B.02C CTS Enabled Interface.

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"), designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45).

1.3.1B.02D CTS Interface Bid

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"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.

1.3.1E.01 Demand Bid

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

1.3.1E.02 Demand Bid Limit

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.03 Demand Bid Screening

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.04 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1F.01 Emergency Load Response Program

The Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2A.02 Economic Maximum.

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9.01 Hot Weather Alert.

"Hot Weather Alert" shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

1.3.9A Increment Offer.

"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.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

1.3.11.02 Load Management Event

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11A.01 Location.

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.13A Maximum Generation Emergency Alert.

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic F~~f~~orce M~~m~~ajeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.24A Pre-Emergency Load Response Program

The Pre-Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve.

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider.

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price.

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation.

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand.

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve.

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2(h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.01A Residual Metered Load.

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.001 Sub-meter.

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38.01 Up-to Congestion Transaction.

"Up-to Congestion Transaction" shall have the meaning specified in Section 1.10.1A of this Schedule.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.38B Virtual Transaction.

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone, when non-extraordinary conditions exist for the applicable twelve month period, as determined by PJM. If the lowest daily zonal peak load from the applicable twelve month period is abnormally low due to extraordinary conditions, as determined by PJM, Zonal Base Load shall mean the next lowest daily zonal peak load that was not affected by extraordinary conditions during the applicable twelve month period, increased by the projected load growth rate for the relevant Zone. For the purposes of this definition, extraordinary conditions shall mean a significant event, or combination of events, that affect the operation of the bulk power system in an atypical manner and results in an abnormal reduction in the consumption of energy within a Zone.

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1.01 Additional Day-ahead Scheduling Reserves Requirement

"Additional Day-ahead Scheduling Reserves Requirement" shall mean the portion of the Day-ahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.001 Base Day-ahead Scheduling Reserves Requirement

"Base Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.01A Cold Weather Alert.

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.02A Coordinated External Transaction.

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.02B Coordinated Transaction Scheduling.

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Section 1.13 of Schedule 1 of this Agreement.

1.3.1B.02C CTS Enabled Interface.

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"), designated in Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45).

1.3.1B.02D CTS Interface Bid

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Section 1.13 of this Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.~~thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.~~

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"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.

1.3.1E.01 Demand Bid

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

1.3.1E.02 Demand Bid Limit

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.03 Demand Bid Screening

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Section 1.10.1B of Schedule 1 of the Operating Agreement.

1.3.1E.04 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1F.01 Emergency Load Response Program

The Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2A.02 Economic Maximum.

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.2B.01 Extended Primary Reserve Requirement

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.2B.02 Extended Synchronized Reserve Requiremen~~ent~~

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9.01 Hot Weather Alert.

"Hot Weather Alert" shall mean the notice provided by PJM to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements and/or unit unavailability to be substantially higher than forecast are expected to persist for an extended period.

1.3.9A Increment Offer.

"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.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

1.3.11.02 Load Management Event

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11A.01 Location.

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.13A Maximum Generation Emergency Alert.

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of *Catastrophic F*orce *M*ajeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

“Non-Variable Loads” shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.24A Pre-Emergency Load Response Program

The Pre-Emergency Load Response Program is the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Section 8 of Schedule 1 of the Operating Agreement and the parallel provisions of Section 8 of Attachment K-Appendix of the Tariff.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29   Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve.

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider.

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price.

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation.

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand.

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve.

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.29G Primary Reserve Requirement

“Primary Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.30 Ramping Capability.

“Ramping Capability” shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

“Real-time Congestion Price” shall mean the Congestion Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

“Real-time Loss Price” shall mean the Loss Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

“Real-time Prices” shall mean the Locational Marginal Prices resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

“Real-time Energy Market” shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

“Real-time System Energy Price” shall mean the System Energy Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

“Reserve Penalty Factor” shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

1.3.31.01 Residual Auction Revenue Rights.

“Residual Auction Revenue Rights” shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2(h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.01A Residual Metered Load.

“Residual Metered Load” shall mean all load remaining in an electric distribution company’s fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

1.3.31.02 Special Member.

“Special Member” shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

1.3.32 Spot Market Backup.

“Spot Market Backup” shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

“Spot Market Energy” shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

“State Estimator” shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.001 Sub-meter.

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.02A Synchronized Reserve Requirement

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38   Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38.01 Up-to Congestion Transaction.

"Up-to Congestion Transaction" shall have the meaning specified in Section 1.10.1A of this Schedule.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.38B Virtual Transaction.

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

1.3.39   Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone, when non-extraordinary conditions exist for the applicable twelve month period, as determined by PJM. If the lowest daily zonal peak load from the applicable twelve month period is abnormally low due to extraordinary conditions, as determined by PJM, Zonal Base Load shall mean the next lowest daily zonal peak load that was not affected by extraordinary conditions during the applicable twelve month period, increased by the projected load growth rate for the relevant Zone. For the purposes of this definition, extraordinary conditions shall mean a significant event, or combination of events, that affect the operation of the bulk power system in an atypical manner and results in an abnormal reduction in the consumption of energy within a Zone.

OA Schedule 1 Section 1.10

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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 12:00 noon 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 dynamically scheduled 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. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited 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.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. 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), 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. Market Sellers shall not designate as a Maximum Emergency offer any portion of their ICAP committed as a Base Capacity Resource during the months of June through September when PJM has issued a Hot Weather Alert or declared an Emergency Action, or committed as a Capacity Performance Resource at any time during the Delivery Year when PJM has issued a Hot Weather Alert, Cold Weather Alert or declared an Emergency Action. Any offer not designated as a Maximum Emergency ~~O~~offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency ~~O~~offers outside of the conditions stipulated above and 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, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, 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 hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all Generation Capacity Resources; and

ix) Shall not exceed an energy offer price of $1,000/megawatt-hour, plus the applicable Primary Reserve Penalty Factor, minus $1.00, for all Economic Load Response Resources;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus the applicable Primary Reserve Penalty Factor, minus $1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus [the applicable Primary Reserve Penalty Factor divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, $1,100/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt 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. 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 per MWh 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 and no-load fees, 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 offer by a Market Seller of a Generation Capacity Resource 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 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. 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. The offer must equal or exceed 0.1 megawatts, and the offer 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. 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).

(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 MW 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, no-load 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.

(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 and no-load fees, 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 and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

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 or no-load fees.

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 dispatch 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 dispatch 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 12:00 p.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) Not earlier than 4:00 p.m. 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 4:00 p.m. to 6:00 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 any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. 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 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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 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 12:00 noon 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 dynamically scheduled 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. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited 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.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. 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), 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. Market Sellers shall not designate as a Maximum Emergency offer any portion of their ICAP committed as a Base Capacity Resource during the months of June through September when PJM has issued a Hot Weather Alert or declared an Emergency Action, or committed as a Capacity Performance Resource at any time during the Delivery Year when PJM has issued a Hot Weather Alert, Cold Weather Alert or declared an Emergency Action.* Any offer not designated as a Maximum Emergency *o*ffer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers *outside of the conditions stipulated above and* 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, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, 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 hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, *unless the resource's cost-based offer, calculated in accordance with Schedule 2 of the Operating Agreement, section 6.4.2 of Attachment K- Appendix of the Tariff and the parallel provisions of Schedule 1 of the Operating Agreement, and PJM Manual 15, exceeds $1,000/megawatt-hour, in which case the resource may submit an offer no greater than an amount equal to that cost-based offer which shall not exceed $1,800/megawatt-hour*; and

ix) Shall not exceed an energy offer price of $1,000/megawatt-hour, plus the applicable ~~Primary~~ Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00, for all Economic Load Response Resources;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus the applicable ~~Primary~~ Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus [the applicable ~~Primary~~ Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, $1,100/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt 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. 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 per MWh 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 and no-load fees, 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 offer by a Market Seller of a Generation Capacity Resource 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 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. 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. The offer must equal or exceed 0.1 megawatts, and the offer 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. 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).

(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 MW 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, no-load 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.

(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 and no-load fees, 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 and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

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 or no-load fees.

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 dispatch 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 dispatch 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 12:00 p.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) Not earlier than 4:00 p.m. 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 4:00 p.m. to 6:00 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 any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. 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 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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 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 12:00 noon 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 dynamically scheduled 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. The source-sink paths on which an Up-to Congestion Transaction may be submitted are limited 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.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. 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), 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. ~~Market Sellers shall not designate as a Maximum Emergency offer any portion of their ICAP committed as a Base Capacity Resource during the months of June through September when PJM has issued a Hot Weather Alert or declared an Emergency Action, or committed as a Capacity Performance Resource at any time during the Delivery Year when PJM has issued a Hot Weather Alert, Cold Weather Alert or declared an Emergency Action.~~ 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 ~~outside of the conditions stipulated above and~~ 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, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, 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 hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generation resource, may specify start-up and no-load fees equal to the specification of such fees for such resource on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all Generation Capacity Resources; and

ix) Shall not exceed an energy offer price of $1,000/megawatt-hour, plus the applicable Primary Reserve Penalty Factor, minus $1.00, for all Economic Load Response Resources;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus the applicable Primary Reserve Penalty Factor, minus $1.00;

b) an approved 60 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA, $1,000/megawatt-hour, plus [the applicable Primary Reserve Penalty Factor divided by 2]; and

c) an approved 120 minute lead time, pursuant to Section A.2 of Attachment DD-1 of the Tariff and the parallel provisions of Schedule 6 of the RAA, $1,100/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt 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. 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 per MWh 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 and no-load fees, 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 offer by a Market Seller of a Generation Capacity Resource 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 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. 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. The offer must equal or exceed 0.1 megawatts, and the offer 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. 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).

(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 MW 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, no-load 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.

(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 and no-load fees, 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 and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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.

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 or no-load fees.

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 dispatch 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 dispatch 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 12:00 p.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) Not earlier than 4:00 p.m. 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 4:00 p.m. to 6:00 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 any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. 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 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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.

OA Schedule 1 Section 3.2

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3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource‘s expected output in the preceding shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource‘s expected output in the following shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a

Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical

performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0 \text{ to } 5 \text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5 \text{ Minutes}) / (5 \text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

$$\text{Accuracy Score} = \max\left((\text{Delay Score}) + (\text{Correlation Score})\right) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point

the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the

Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its physically determined parameter limitations due to external requirements such as fuel delivery arrangements, for example, will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection.

Consistent with Sections 1.10.1 and 6.6 hereof, resources with notification or start up times greater than one day that are committed by the Office of the Interconnection will not receive Operating Reserve Credits nor 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.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour the unit operates in condensing and generation mode.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and
>
> where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

> URTLMP equals the real time LMP at the unit's bus;
>
> UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for

Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_t = \frac{(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1})}{(\mathbf{UDSLAtime}_{t-1})}$$

$$\mathbf{RL\_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_t * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh - Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing

Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized

Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource’s output or the Demand Resource’s consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource’s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in an hour in excess of the Non-Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

> (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.
>
> (ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UDALMP equals the day-ahead LMP at the unit's bus;
>
> DAG equals the day-ahead scheduled unit output for the hour;
>
> UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and
>
> where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the

Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource‘s expected output in the preceding shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource‘s expected output in the following shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a

Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical

performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

$$\text{Error} = \text{Average of Abs}\left((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})\right);\text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

$$\text{Accuracy Score} = \max\left((\text{Delay Score}) + (\text{Correlation Score})\right) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point

the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the

Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its physically determined parameter limitations due to external requirements such as fuel delivery arrangements, for example, will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection.

Consistent with Sections 1.10.1 and 6.6 hereof, resources with notification or start up times greater than one day that are committed by the Office of the Interconnection will not receive Operating Reserve Credits nor 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.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour the unit operates in condensing and generation mode.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh *and greater than the Market Seller's lowest* *available and applicable cost-based offer*, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price *for a market based offer* is greater than $1,000/MWh *and greater than the Market Seller's lowest available and applicable cost-based offer*, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\text{Ramp\_Request}_t = \left(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}\right) / \left(\text{UDSLAtime}_{t-1}\right)$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh - Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing

Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource greater than $1,800/megawatt-hour, determined in accordance with Schedule 2 of the Operating Agreement and PJM Manual 15 and that would otherwise be included in a cost-based offer, will be eligible to receive credit for Operating Reserves at a level consistent with the difference between the resource's calculated costs above $1,800/megawatt-hour and the overall energy offer cap of $1,800/megawatt-hour. Before receiving any credit for Operating Reserves, all relevant documentation demonstrating the calculation of costs greater than $1,800/megawatt-hour must be submitted to the Office of the Interconnection and the Market Monitoring Unit. The Office of the Interconnection must approve any Operating Reserves credits paid to a Market Seller under this subsection (r). Market Sellers requesting costs under this subsection (r) shall not be eligible to include an adder specified in section 6.4.2 hereof in its cost-based offers for the generation resource.

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the O~~o~~perating D~~d~~ay. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve R~~r~~equirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the ~~Synchronized~~ applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the ~~Synchronized~~ Reserve Penalty Factors for the Synchronized Reserve Requirement and ~~the~~ Primary Reserve ~~Penalty~~Requirement ~~Factor~~ for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the ~~Primary~~ Reserve Penalty Factors for the Primary Reserve Requirement and the ~~Synchronized Reserve Penalty Factor~~Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The ~~Synchronized~~ Reserve Penalty Factors for the Synchronized Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the O~~o~~perating D~~d~~ay. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve R~~r~~equirement or Extended Primary Reserve Requirement. When the Primary Reserve R~~r~~equirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the ~~Primary~~applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone.~~will be determined as the Primary Reserve Penalty Factor.~~ If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the ~~Primary~~ Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The ~~Primary~~ Reserve Penalty Factors for the Primary Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in an hour in excess of the Non-Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead

Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

~~(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).~~

(d) The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

(i) A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.

(ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output in the preceding shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a

Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical

performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}((\delta - 5\text{ Minutes}) / (5\text{ Minutes})).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

$$\text{Error} = \text{Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal))}; \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

$$\text{Accuracy Score} = \max((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point

the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the

Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its physically determined parameter limitations due to external requirements such as fuel delivery arrangements, for example, will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection.

Consistent with Sections 1.10.1 and 6.6 hereof, resources with notification or start up times greater than one day that are committed by the Office of the Interconnection will not receive Operating Reserve Credits nor 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.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour the unit operates in condensing and generation mode.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the applicable offer for energy on which the generating unit was committed in the Real-time Energy Market, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

The deviation of the generating unit's output is equal to the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

~~{(LMPDMW - AG) x (URTLMP – UB)}, where:~~

~~LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;~~

~~AG equals the actual hourly integrated output of the unit;~~

~~URTLMP equals the real time LMP at the unit's bus;~~

~~UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and~~

~~where URTLMP - UB shall not be negative.~~

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) for each hour a~~if the~~ unit is scheduled to produce energy in the D~~d~~ay-ahead Energy M~~m~~arket, but the unit is not called on by the Office of the Interconnection~~PJM~~ and does not operate in real time, then the Market Seller shall be credited~~ hourly~~ in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the applicable offer for energy on which the generating unit was committed in the Day-ahead Energy Market, inclusive of no-load costs, plus (D) the start-up cost, divided by the hours committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market; or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

~~(i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:~~

~~URTLMP equals the real time LMP at the unit's bus;~~

~~UDALMP equals the day-ahead LMP at the unit's bus;~~

~~DAG equals the day-ahead scheduled unit output for the hour;~~

~~UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in~~

~~which case the offer for the unit will be determined from the cost-based schedule; and~~

~~where URTLMP - UDALMP and URTLMP – UB shall not be negative.~~

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the applicable offer for energy on which the generating unit was committed in the Real-time Energy Market, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

The deviation of the generating unit's output is equal to the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time

Locational Marginal Price, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.

~~{(LMPDMW - AG) x (URTLMP - UB)}, where:~~

~~LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;~~

~~AG equals the actual hourly integrated output of the unit;~~

~~URTLMP equals the real time LMP at the unit's bus;~~

~~UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and~~

~~where URTLMP - UB shall not be negative.~~

~~In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.~~

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as “MaxGen Conditions”). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\text{Ramp\_Request}_t = (\text{UDStarget}_{t-1} - \text{AOutput}_{t-1}) / (\text{UDSLAtime}_{t-1})$$

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh - Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating

Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Synchronized Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource’s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer’s total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour (“Non-Synchronized Reserve Obligation”). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factors for the Primary Reserve Requirement shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in an hour in excess of the Non-Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

(i) A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.

(ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the applicable offer for energy on which the generating unit was committed in the Real-time Energy Market, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

The deviation of the generating unit's output is equal to the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time Locational Marginal Price, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, minus the actual hourly integrated output of the unit.

For pool-scheduled generating units, their applicable offer for energy is the offer on which the resource was committed. For self-scheduled generating units, their applicable offer for energy shall equal the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule.
~~{(LMPDMW – AG) x (URTLMP – UB)}~~

~~where:~~

~~LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;~~

~~AG equals the actual hourly integrated output of the unit;~~

~~URTLMP equals the real time LMP at the unit's bus;~~

~~UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and~~

~~where URTLMP – UB shall not be negative.~~

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in

Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element (“contingency flow”) exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility (“post-contingency operation”). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit’s operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource’s hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource’s start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit’s cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Internal Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the

expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Seller or Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output in the preceding shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Internal Market Buyer in a

Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical

performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

$$\text{Error} = \text{Average of Abs}\left((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})\right);\text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

$$\text{Accuracy Score} = \max\left((\text{Delay Score}) + (\text{Correlation Score})\right) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point

the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the

Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its ~~physically determined~~unit-specific parameters ~~limitations due to external requirements such as fuel delivery arrangements, for example,~~ will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

~~Consistent with Sections 1.10.1 and 6.6 hereof, resources with notification or start up times greater than one day that are committed by the Office of the Interconnection will not receive Operating Reserve Credits nor 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.~~

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour the unit operates in condensing and generation mode.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and
>
> where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

> (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of

the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> LMPDMW equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and
>
> where URTLMP - UB shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted in subsection (h)(ii) below and in the PJM Manuals; (2) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (3) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (4) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a

Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead

Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request_t} = \mathbf{(UDStarget_{t-1} - AOutput_{t-1})} \Big/ \mathbf{(UDSLAtime_{t-1})}$$

$$\mathbf{RL\_Desired_t} = \mathbf{AOutput_{t-1}} + \left(\mathbf{Ramp\_Request_t * Case\_Eff\_time_{t-1}}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh - Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined n section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement.

A Market Participant that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts, if any, described in subsections (g), (h) and (i) of this section.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange

Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B)- the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or

Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

i. $250/MWh for the 2012/2013 Delivery Year;

ii. $400/MWh for the 2013/2014 Delivery Year;

iii. $550/MWh for the 2014/2015 Delivery Year; and

iv. $850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in an hour in excess of the Non-Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each

Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

OA Schedule 1 Section 5.2

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5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Offer and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right or had an Up-to Congestion Transaction that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for a path at or near the path of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Offer, Decrement Bid or Up-to Congestion Transaction is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC’s rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an unanticipated event outside the control of PJM~~force majeure~~ that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target

Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Offer and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right or had an Up-to Congestion Transaction that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for a path at or near the path of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Offer, Decrement Bid or Up-to Congestion Transaction is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified ~~monthly~~ period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified ~~monthly~~ period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions. In addition, PJM may remove or lower the increased capability limits, if feasible, during subsequent FTR Auctions if the removal or lowering of the increased capability limits does not impact Auction Revenue Rights funding and net auction revenues are positive.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an *unanticipated* event *outside the control* of *PJM* that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule

1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target

Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 “Distribution of Excess Congestion Charges.”

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

RAA Schedule 6

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SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Direct Load Control, as further specified in section G and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically

incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total

Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- if applicable, Direct Load Control (DLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the

current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the

threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following ~~three~~four ways:

Direct Load Control (DLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for DLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

The Nominated Value for a Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

For Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance for Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for GLD, and will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(iii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered DLC programs. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour". The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manual. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and DLC programs to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value, ~~which~~

- For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;
- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

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The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, ~~T~~the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy

Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, *a Base Capacity Demand Resource* or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically

incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total

Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the

PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the

current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the

threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, *and for the 2018/2019 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement*. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following *four* ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on LDLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- Supplemental status reports, detailing Demand Resources available, as requested by PJM;
- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, t~~T~~he Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, ~~LSE contact information,~~ number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, ~~F~~for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Prior to June 1, 2016, c~~C~~ompliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for ~~FSL~~Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for ~~GLD~~ Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance~~, and~~ will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii~~i~~) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour". The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manual. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak *summer and winter* periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project

location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value,

- *For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;*
- *For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource* shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday*; and*
- *For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.*

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. *For Delivery Years through May 31, 2018, t*he Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. *For the 2018/2019 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.*

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall

not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Direct Load Control, as further specified in section G and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically

incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total

Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- if applicable, Direct Load Control (DLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the

current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the

threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand

Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four ways:

Direct Load Control (DLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for DLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load

reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

The Nominated Value for a Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

For Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are

responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.
For Load Management Events occurring through the May 31, 2018 and for Load Management Events occurring during the months of June through September of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance for Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for GLD, and will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(iii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered DLC programs. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour". The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manual. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events occurring during the months of October through May of the 2018/2019 Delivery Year and subsequent Delivery Years:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and DLC programs to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value,

   - For Delivery Years through May 31, 2018, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part

of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically

incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total

Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the

PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the

current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the

threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand

Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction

for LDLC programs. Each Curtailment Service Provider relying on LDLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- Supplemental status reports, detailing Demand Resources available, as requested by PJM;
- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load

reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are

responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events for all Demand Resources not committed as a Capacity Performance Resource occurring through ~~the~~ May 31, 2018, and for Load Management Events for Demand Resources committed as a Base Capacity Resource or a Capacity Performance Resource occurring during the months of June through September ~~of the 2018/2019 Delivery Year and subsequent Delivery Years~~:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour". The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manual. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events for Demand Resources committed as a Base Capacity Resource or as a Capacity Performance Resource occurring during the months of October through May ~~of the 2018/2019 Delivery Year and subsequent Delivery Years~~:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of Schedule 1 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or

after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the

applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, of for FRR Capacity Plans the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

Attachment C

Copy of Redlines to Show Ministerial Corrections to
Parallel Section:
OATT Attachment DD-1
RAA Schedule 6

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource, or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance

with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the

Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand

Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand

response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights

and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine

reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for LDLC programs. Each Curtailment Service Provider relying on DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office

of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events for all Demand Resources not committed as a Capacity Performance Resource occurring through May 31, 2018, and for Load Management Events for Demand Resources committed as a Base Capacity Resource or a Capacity Performance Resource occurring during the months of June through September:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection, for at least 30 minutes of the clock hour (i.e., “partial dispatch compliance hour”). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events for Demand Resources committed as a Base Capacity Resource or as a Capacity Performance Resource occurring during the months of October through May:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer’s Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of Schedule 1 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011~~2~~. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer

the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

~~The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.~~

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering

an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Legacy Direct Load Control (prior to June 1, 2016), as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is a Limited Demand Resource, an Extended Summer Demand Resource, a Base Capacity Demand Resource or an Annual Demand Resource.

2. A Demand Resource must achieve its full load reduction within the following time period:

(a) For the 2014/2015 Delivery Year, Curtailment Service Providers may elect a notification time period from the Office of the Interconnection of 30, 60 or 120 minutes prior to their Demand Resources being required to fully respond to a Load Management Event.

(b) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that resource is submitted in accordance with Attachment K-Appendix of this Tariff. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource is physically

incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that registered the resource must demonstrate that:

1) The manufacturing processes for the Demand Resource require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

2) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

3) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

4) The Demand Resource is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) business days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) business days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) business days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in section A-1 of Schedule 6, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 15 business days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total

Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers;
- assumptions regarding regulatory approval of program(s), if applicable; and
- Prior to June 1, 2016: if applicable, Legacy Direct Load Control (LDLC) program details such as: a description of the cycling control strategy, any assumptions regarding switch operability rate, and a list (and copy) of all load research studies used to develop the estimated nominated ICAP value per customer (i.e., the per-participant impact).

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the

PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the

current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification; and

(b) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the

threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 15 business days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 business days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 business days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 business days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

for the Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the product of the Nominated Value of the Demand Resource, times the DR Factor, times the Forecast Pool Requirement, and for the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans the 2019/2020 Delivery Year and subsequent Delivery Years, the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources, divided by the total Nominated Value of Demand Resources in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand

Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resources in the following four ways:

Prior to June 1, 2016: Legacy Direct Load Control (LDLC) – Load management that is initiated directly by the Curtailment Service Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Curtailment Service Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction

for LDLC programs. Each Curtailment Service Provider relying on ~~L~~DLC load management must periodically update its LDLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

Customer Baseline Load (CBL) - Load management achieved by an end-use customer as measured by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of the Operating Agreement.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- Supplemental status reports, detailing Demand Resources available, as requested by PJM;
- Entry of customer-specific Demand Resource credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource events, prepared in accordance with the PJM Manuals.

I. The Nominated Value of each Demand Resource shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource load

reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Curtailment Service Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

Prior to June 1, 2016, the Nominated Value for a Legacy Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections J and K.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource information, to verify the amount of load management available and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

Prior to June 1, 2016, for Legacy Direct Load Control programs, the Curtailment Service Provider must provide information detailing the number of active participants in each program. Other information on approved LDLC programs will be provided by PJM.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource events. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resources dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are

responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

For Load Management Events for all Demand Resources not committed as a Capacity Performance Resource occurring through May 31, 2018, and for Load Management Events for Demand Resources committed as a Base Capacity Resource or a Capacity Performance Resource occurring during the months of June through September:

Prior to June 1, 2016, compliance for Legacy Direct Load Control programs will consider only the transmission of the control signal. Curtailment Service Providers are required to report the time period (during the Demand Resource event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the Load Management Event for non-interval metered LDLC programs, prior to June 1, 2016. Compliance is averaged over the Load

Management Event, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). The registered capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour and as defined in the Manuals. Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute.

For Load Management Events for Demand Resources committed as a Base Capacity Resource or as a Capacity Performance Resource occurring during the months of October through May:

Compliance is determined on an individual customer basis by comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of Section 3.3A.2 or 3.3A.2.01 of Schedule 1 of the Operating Agreement.

For all Delivery Years:

Demand Resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and LDLC programs (prior to June 1, 2016) to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

L. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of

the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For Delivery Years through May 31, 2018 for all Energy Efficiency Resources not committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday;

- For the 2018/2019 and 2019/2020 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Base Capacity Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday; and

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource for the 2016/2017 and 2017/2018 Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A

Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. For Delivery Years through May 31, 2018, or for FRR Capacity Plans for Delivery Years through May 31, 2019, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement. For the 2018/2019 Delivery Year and subsequent Delivery Years, or for FRR Capacity Plans for the 2019/2020 Delivery Year and subsequent Delivery Years, the Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.