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March 23, 2018

The 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. EL17-775-000
Implementation of Order No. 825 – Five Minute Settlement Intervals*

Dear Secretary Bose:

In compliance with the February 21, 2018 Order of the Federal Energy Regulatory Commission (“Commission”) in the above referenced proceeding,¹ PJM Interconnection, L.L.C. (“PJM”) submits modifications to the PJM Open Access Transmission Tariff (“Tariff”) and Amended and Restated Operating Agreement of PJM (“Operating Agreement”). As provided in the February 21, 2018 Order, the effective date for the changes herein will be April 1, 2018 for the revised settlement interval and May 11, 2017 for the modified shortage pricing interval, respectively, as further explained below.² In addition to the compliance revisions, PJM submits a minor technical correction with respect to the use of the scaling calculation for generation resources in Revenue Data for Settlements in order to prevent unreasonable and unintended results from occurring due to a sign error in the application of the formula.

I. BACKGROUND

In Order No. 825, the Commission required that each regional transmission organization align settlement and dispatch intervals to (1) settle energy transactions in its real-time markets at

¹ *PJM Interconnection, L.L.C., et al.*, 162 FERC ¶ 61,150 (2018) (“February 21, 2018 Order”).

² See February 21, 2018 Order at P 66-67.

the same time interval it dispatches energy; (2) settle ancillary service transactions in its real-time markets at the same time interval it prices ancillary service transactions; (3) settle intertie transactions in the same time interval it schedules intertie transactions; and (4) establish a mechanism to trigger shortage pricing for any interval in which a shortage of energy or ancillary services is indicated during the pricing of resources for that interval.

On January 11, 2017, PJM submitted revisions to the Tariff and Operating Agreement in order to align settlement and dispatch intervals, and change the rules regarding when shortage pricing is triggered in compliance with Order No. 825.³ Thereafter, on February 23, 2017, Commission staff issued a data request seeking additional information related to intertie transactions, behind-the-meter generation, energy withdrawals by generation resources, demand response,⁴ and operating reserves deviation charges.⁵ PJM submitted responses to the data request on March 27, 2017⁶ and an amended compliance filing to correct three minor errors in the language PJM originally proposed in the Compliance Filing related to the implementation of 5-minute settlements on August 14, 2017.⁷ Subsequently, the Commission accepted PJM's compliance filing subject to the conditions described below in its February 21, 2018 Order.⁸

³ PJM Interconnection, L.L.C., *Order No. 825 Compliance Filing*, Docket No. ER17-775-000 (Jan. 11, 2017).

⁴ For the purpose of this answer, capitalized terms not defined herein shall have the meaning as contained in the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., ("Operating Agreement") or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA").

⁵ Letter Requesting PJM Interconnection, L.L.C. To Provide Additional Information, Docket No. ER17-775-000 (Feb. 23, 2017).

⁶ PJM Interconnection, L.L.C., *PJM Response to February 23, 2017 Deficiency Letter, L.L.C.*, Docket No. ER17-775-000 (Mar. 27, 2017).

⁷ PJM Interconnection, L.L.C., *Amended Compliance Filing of PJM Interconnection, L.L.C.*, Docket No. ER17-775-000 (Aug. 14, 2017).

⁸ February 21, 2018 Order at P 1.

II. SATISFACTION OF THE COMPLIANCE REQUIREMENTS OF THE FEBRUARY 21, 2018 ORDER

In accordance with the Commission's February 21, 2018 Order, PJM submits further revisions to the Tariff, Attachment K-Appendix, sections 3.1A and 3.2.2(a), Operating Agreement, Schedule 1, sections 3.1A and 3.2.2(a), and Tariff, Attachment DD, section 10A(g).

A. Demand Response Resources Subject to All Applicable Provisions Proposed for Generation Resources

In the January 11 Filing, PJM proposed to replace the hourly settlement interval applicable to the Real-time Energy Market and ancillary services markets with a 5-minute settlement interval based on 5-minute Locational Marginal Price. PJM proposed that for those generation resources for which revenue meter data is only available on an hourly basis, PJM will determine the Revenue Data for Settlements using real-time telemetry data or State Estimator⁹ (i.e. real-time scaling data) values to account for generation resources' intra-hour fluctuations in output.¹⁰ PJM further proposed that for resources and load for which real-time scaling data is not available, PJM will determine Revenue Data for Settlements using a flat profile.¹¹ Finally, PJM proposed to apply flat profiling to determine Revenue Data for Settlements for all demand response resources.¹²

The Commission found that by limiting demand response resources to only submitting hourly revenue meter data, PJM's proposal may not provide a proper price signal to all resources

⁹ The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable. *See* Tariff, Attachment K-Appendix, section 2.3.

¹⁰ PJM Interconnection, L.L.C., *Order No. 825 Compliance Filing*, transmittal letter at P12-14, Docket No. ER17-775-000 (Jan. 11, 2017).

¹¹ *Id.*

¹² *Id.*

because demand response resources would not be treated consistently with other resources.¹³ Consequently, the Commission “direct[ed] PJM to insert language clarifying that demand response resources will be subject to all of the applicable provisions proposed for generation resources in section 3.1A.”¹⁴ As directed by the Commission’s Order, PJM will allow demand response resources to be settled using a flat profile or five-minute revenue meter data. Also, consistent with the existing language in Tariff, Attachment K-Appendix, section 3.1A(b) and Operating Agreement, Schedule 1, section 3.1A(b), once a Market Participant submits five-minute revenue meter data for a demand response resource, the Market Participant must continue to provide revenue meter data for such demand response resource on a five-minute basis. To effectuate the Commission’s compliance order, PJM proposes to revise Tariff, Attachment K-Appendix, section 3.1A(f) and Operating Agreement, Schedule 1, section 3.1A(f) in order reflect the changes required by the Commission, as shown in blackline below:

- (f) For ~~D~~emand ~~R~~esponse resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or is the hourly revenue meter data submitted to the Office of the Interconnection and flat profiled over a set of dispatch intervals in the hour.

In addition, PJM also proposes to revise Tariff, Attachment K-Appendix, section 3.3A.5(c) and Operating Agreement, Schedule 1, section 3.3A.5(c) to remove references to “hourly energy consumption” in order to treat demand response resources consistently with other resources, as shown in blackline below:

- (c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use

¹³ February 21, 2018 Order at P 45.

¹⁴ *Id.*

customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event that the end-use customer's ~~hourly~~ energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount the end-use customer's ~~hourly~~ energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

B. Clarification to Settle Regulation on the Same Time Interval That it is Priced

In the January 11 Filing, PJM also proposed revisions to describe how Regulation would be settled on a 5-minute basis. Specifically, PJM explained that a Market Participant with an hourly Regulation obligation would be charged the pro rata share of the sum of the quantity of Regulation provided in each Real-time Settlement Interval multiplied by the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation. The Commission found that the proposed language was unclear regarding whether PJM would settle Regulation on the same time interval that it would be priced. As a result, the Commission directed PJM to modify the proposed tariff language to include a mathematical formula that illustrates how Regulation charges will be calculated and settled.¹⁵ In compliance with the Commission's order, PJM clarifies the equation for how Regulation charges are calculated and settled in Tariff, Attachment K-Appendix, section 3.2.2(a); and Operating Agreement, Schedule 1, section 3.2.2(a), as shown in blackline below:

- (a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's

¹⁵ February 21, 2018 Order at P 46.

total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour (“Regulation Obligation”). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the ~~quantity of regulation provided in each Real-time Settlement Interval times the clearing price~~ Regulation market performance clearing price credits and Regulation market capability clearing price credits for ~~all the~~ all the Real-time Settlement Intervals in ~~the an~~ an hour associated with that obligation.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

To ensure consistency of terms in the aforementioned revision, PJM also proposes to revise Tariff, Attachment K-Appendix, sections 3.2.2(g) and 3.2.2(h); and Operating Agreement, Schedule 1, sections 3.2.2(g), and 3.2.2(h), as shown in blackline below:

(g) To determine the ~~performance~~ Regulation market performance 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 performance -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 performance -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 capability -clearing price for each Regulation Zone by subtracting the ~~performance~~ Regulation market performance -clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the ~~capability~~ Regulation market capability clearing price for that market Real-time Settlement Interval.

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

C. Update Language to Ensure Accuracy for the Calculation of Bonus Performance

Finally, in the February 21, 2018 Order, the Commission agreed with the PJM Independent Market Monitor's suggestion to require changing "hour" to "interval" for consistency regarding the units of time measurement for the definition of resource bonus performance.¹⁶ PJM also agrees that this clarification is beneficial and revises the relevant sentence in Tariff, Attachment DD, section 10A(g), as shown in blackline below:

- (g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval, that provided energy or load reductions above the levels expected for such resource during such ~~hour~~interval.

¹⁶ February 21, 2018 Order, at P 52.

III. TECHNICAL CORRECTION TO CALCULATION USED IN REVENUE DATA FOR SETTLEMENTS

In addition to the aforementioned revisions, PJM submits a technical correction with respect to the use of the scaling calculation for generation resources in Revenue Data for Settlements. As explained in the December 8, 2017 notice concerning the implementation date of five-minute settlements,¹⁷ PJM has been working diligently to ensure that the implementation of five-minute settlements will begin on April 1, 2018. As part of this process, PJM conducted five-minute settlement market trials working with its Market Participants. During this testing period, PJM identified an unintended error regarding the calculation used in Revenue Data for Settlements when generation resources elect to submit hourly revenue meter data. More particularly, in specific conditions when State Estimator or telemetry interval values within an hour are both positive and negative, the hourly average of the State Estimator or telemetry values can result in a different sign than the submitted hourly revenue meter value in Power Meter. When this condition occurs, the resulting scaled values are incorrect, and consequently generation resources will not be accurately settled. In short, as a result of the mathematical effect of changing signs, an unintended result occurs. This is clearly an error which PJM seeks to correct in order to be consistent with the intent of the filing and the Commission's Order. In addition, correcting this error will prevent unreasonable and unintended results from occurring due to a sign error in the application of the formula.

¹⁷ PJM Interconnection, L.L.C., *Notice of PJM Interconnection L.L.C. Concerning Implementation Date of 5-Minute Settlements*, Docket No. ER17-775-000 (December 8, 2017).

To address this issue, PJM designed a limited modification to the scaling calculation that corrects the flaw in the calculation of Revenue Data for Settlements, while ensuring that the amended calculation produces the same results as initially proposed for all generation resources when this specific condition does not occur. Specifically, PJM proposes to update the calculation used to determine Revenue Data for Settlements from five-minute telemetry values or State Estimator values *multiplied by a scaling factor to plus an offset*. The addition of an offset ensures the Revenue Data for Settlements interval value is consistent with the sign convention of the five-minute telemetry or State Estimator value. This requires only a minor modification to Tariff, Attachment K-Appendix, section 3.1A(d) and Operating Agreement, Schedule 1, section 3.1A(d), as shown in blackline below:

- i) For each Real-time Settlement Interval, the Revenue Data for Settlements is equal to the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, as further described in the PJM Manuals for an hour ~~multiplied by plus an offset~~ scaling factor. The scaling factor is equal to the ratio of the hourly revenue meter data to the hourly integrated telemetry values or hourly integrated State Estimator values calculated according to section 2.3 of this Schedule. The offset is the difference between the hourly meter data value and (the hourly integrated telemetry or hourly integrated State Estimator value) times 12 and multiplied by absolute value of the ratio of (the Real-time Settlement Interval telemetry or State Estimator value) and (the absolute value of the sum of the Real-time Settlement Interval telemetry or State Estimator values for the hour).

IV. EFFECTIVE DATE

Consistent with the February 21, 2018 Order, PJM submits modified Tariff sheets to reflect the effective date of April 1, 2018 for all settlement interval revisions, including the changes on compliance filed herein. In addition, PJM submits modified Tariff sheets to reflect May 11, 2017, as the effective date for all other shortage pricing reform revisions.

V. DOCUMENTS ENCLOSED

PJM encloses the following:

1. This transmittal letter;
2. Attachment A – Revisions to the Tariff and Operating Agreement, in redlined format; and
3. Attachment B – Revisions to the Tariff and Operating Agreement, in clean format.

VI. COMMUNICATIONS

Correspondence and communications with respect to this filing should be sent to the following persons:

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VII. 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,¹⁸ 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.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

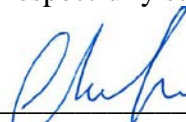
¹⁸ See 18 C.F.R §§ 35.2(e) and 385.2010(f)(3).

PJM Region¹⁹ alerting them that this filing has been made by PJM today and is available by following such link.

VIII. CONCLUSION

PJM respectfully requests that the Commission accept this compliance filing and grant effective dates of May 11, 2017 for the shortage pricing reform revisions and April 1, 2018, for the settlement reform revisions.

Respectfully submitted,



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¹⁹ PJM already maintains, updates, and regularly uses e-mail lists for all PJM members and affected commissions.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Audubon, PA, this 23rd day of March, 2018.



Chenchao Lu
Attorney for PJM Interconnection, L.L.C.

Attachment A

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

(Marked / Redline Format)

Section(s) of the
PJM Open Access Transmission Tariff
(Marked / Redline Format)

3.1 Introduction.

This schedule sets forth the accounting and billing principles and procedures for the purchase and sale of services on the PJM Interchange Energy Market and for the operation of the PJM Region.

3.1A Revenue Data for Settlements

- (a) Revenue Data for Settlements are energy quantities used for accounting and billing and are determined based on data submitted by a Market Participant.
- (b) Once a Market Participant submits five-minute revenue meter data for a resource, the Market Participant must continue to provide revenue meter data for that resource on a five-minute basis.
- (c) For generation resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or hourly revenue meter data submitted to the Office of the Interconnection as adjusted in accordance with subsection (d). The revenue meter data for a generation resource can be either positive, representing energy injection, or negative, representing an energy withdrawal.
- (d) Revenue Data for Settlements for generation resources for which Market Participants submit hourly revenue meter data to the Office of the Interconnection shall be calculated as follows:
 - i) For each Real-time Settlement Interval, the Revenue Data for Settlements is equal to the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, as further described in the PJM Manuals for an hour ~~multiplied by plus an offset scaling factor. The scaling factor is equal to the ratio of the hourly revenue meter data to the hourly integrated telemetry values or hourly integrated State Estimator values calculated according to section 2.3 of this Schedule. The offset is the difference between the hourly meter data value and (the hourly integrated telemetry or hourly integrated State Estimator value) times 12 and multiplied by absolute value of the ratio of (the Real-time Settlement Interval telemetry or State Estimator value) and (the absolute value of the sum of the Real-time Settlement Interval telemetry or State Estimator values for the hour).~~
 - ii) If the difference between the average of the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, and further described in the PJM Manuals, for an hour and the hourly revenue meter data is greater than 20 percent of the hourly revenue meter data and greater than 10 MW, then the Revenue Data for Settlements is a flat profile of the hourly revenue meter data equally apportioned over the five minute intervals in the hour.
 - iii) If a Market Participant is unable to provide telemetry for a generation resource, the Revenue Data for Settlements will be a flat profile of the hourly revenue meter data equally apportioned over the five-minute intervals in the hour.

- (e) For all energy transactions for which telemetry is not available, the Revenue Data for Settlements is the submitted value to the Office of the Interconnection adjusted for any curtailment and flat profiled over the set of five-minute intervals that the energy transaction is scheduled and dispatched.
- (f) For ~~D~~demand ~~R~~esponse resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or is the hourly revenue meter data submitted to the Office of the Interconnection and flat profiled over a set of dispatch intervals in the hour.
- (g) For load, the Revenue Data for Settlements is the hourly submitted value to the Office of the Interconnection and flat profiled equally apportioned over the five-minute intervals in the hour.

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

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

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

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

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

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

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

3.2.2 Regulation.

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

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

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

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

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

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a

generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour, in accordance with the PJM Manuals and below.

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

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

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

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

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

(g) To determine the ~~performance~~-Regulation market ~~performance~~-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 ~~performance~~-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 ~~performance~~-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 ~~capability~~-clearing price for each Regulation Zone by subtracting the ~~performance~~-Regulation market ~~performance~~-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the ~~capability~~-Regulation market ~~capability~~-clearing price for that market Real-time Settlement Interval.

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

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

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

factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

The Office of the Interconnection shall calculate an 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:

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

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

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:

$$\text{Accuracy Score} = \text{max} ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

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

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the 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 Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller.

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

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

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate

in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations .

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

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

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

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

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

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

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

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

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

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

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

(f) A Market Seller'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 , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the 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 market-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) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement

Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

- 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the 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 Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
- 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(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 of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the

requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the 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 market-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 shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

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

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

Where:

h = the hours in the applicable Operating Day;

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

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

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

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

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

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

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

interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

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

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

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

(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 Dynamic Transfers to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller’s lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to

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

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

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 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:

$$\text{Ramp_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLA}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

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 for each Real-time Settlement Interval. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW for each Real-time Settlement Interval.

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

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

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

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

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

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

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

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

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

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

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

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

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

resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

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

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

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

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

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource *that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's*

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

3.2.3A Synchronized Reserve.

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

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

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

the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur in a Real-time Settlement Interval.

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

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

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

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

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

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

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

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

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

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

C = 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; and

D = 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where:

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;

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

C = 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; and

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

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

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

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption

achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

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

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves

and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a 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 Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

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

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

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource;

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-

ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJM Settlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJM Settlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the

“ending MW usage” (as defined above) and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the time of the “ending MW usage” in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

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

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the 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 market-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) $\{(URTLMP - UDALMP) \times DAG\}$, or (ii) $\{(URTLMP - UB) \times DAG\}$ 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 market-based schedule and the offer associated with that market-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 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 $\{(AG - LMP_{DMW}) \times (UB - URTLMP)\}$ where:

AG equals the actual output of the unit;

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

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

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

where $UB - URTLMP$ shall not be negative.

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

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

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

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

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

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

in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to

provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) 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, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by on-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, except for the months of June through September in the Delivery Year, the following formula shall be used to measure an Emergency and Pre-Emergency Load Response participant's demand reductions when determining compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

- (a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.
- i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:
1. NERC holidays;
 2. Weekend days;
 3. Event days. For the purposes of this section an event day shall be either:
 - (i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - (ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer

locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

- ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

- iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

- i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.
 2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
 3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office

of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\text{Delta LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and Delta LMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is

available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) of this Schedule and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in section 1.10.1A(k) of this Schedule, and may update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event that the end-use customer's ~~hourly~~ energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount the end-use customer's ~~hourly~~ energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$ and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;
 RTL_{iz} is the real-time load for LSE i in zone z ;
 X is the total export quantity from PJM in that hour; and
 X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJM Settlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under

the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;

v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

10A. CHARGES FOR NON-PERFORMANCE AND CREDITS FOR PERFORMANCE

(a) For the 2018/2019 Delivery Year and any subsequent Delivery Year (and for certain purposes for the 2016/2017 and 2017/2018 Delivery Years as provided in subsections (h) and (i) hereof), each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), and each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation or demand response resources that perform during such hour in excess of the level expected based on commitments (if any) of such resources.

(b) Performance shall be measured for purposes of this assessment during each Performance Assessment Interval.

(c) For each Performance Assessment Interval, the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource and Locational UCAP has fallen short of the performance expected of such committed Capacity Resource, and the magnitude of any such shortfall, based on the following formula:

Performance Shortfall = Expected Performance - Actual Performance

Where the result of such formula is a positive number and where:
Expected Performance =

for Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve a declared Emergency Action; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and Capacity Storage Resources: [(Resource Committed Capacity * the Balancing Ratio)];

where

Resource Committed Capacity = the total megawatts of Unforced Capacity of the Capacity Resource committed by such Capacity Market Seller or Locational UCAP Seller; and

The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports and Demand Response Bonus Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only

for any Performance Assessment Interval for which performance by any external Generation Capacity Resource would have helped resolve the Emergency Action that was the subject to the Performance Assessment Hour; and provided further that for any Delivery Year up to and including the 2019/2020 Delivery Year, Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

All Committed Generation and Storage Capacity = the total megawatts of Unforced Capacity of all Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and all Capacity Storage Resources committed by all Capacity Market Sellers, FRR Entities, Locational UCAP Sellers;

All Actual Generation Performance and Storage Resource Performance = the total amount of Actual Performance for all generation resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and storage resources during the interval;

Net Energy Imports = the sum of interchange transactions importing energy into PJM (not including those associated with external Generation Capacity Resources and therefore included in All Actual Generation Performance) minus the sum of interchange transactions exporting energy out of PJM, but not less than zero;

Demand Response Bonus Performance = the sum of Bonus performance provided by Demand Response resources as calculated in (g) below;

and for Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades: Resource Committed Capacity;

where

Resource Committed Capacity = the total megawatts of capacity committed from such Capacity Resource committed capacity without making any adjustment for the Forecast Pool Requirement

and

Actual Performance =

for each generation resource, the metered output of energy delivered by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each storage resource, the metered output of energy delivered by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each Demand Resource, the demand response provided by such resource, plus such resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval, as established through the PJM demand response settlement procedure consistent with the standards specified in Schedule 6 of the RAA;

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; and

for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Interval, and zero if it is not in service during such Performance Assessment Interval.

Such calculation shall encompass all resources located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment

Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval. For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Interval shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.

(d) Notwithstanding subsection (c) above, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, or was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the Interconnection, based on a determination by the Office of the Interconnection that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM Region. Such a resource shall be considered in the calculation of a Performance Shortfall if it otherwise was needed and would have been scheduled by the Office of the Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to: (i) any operating parameter limitations submitted in the resource's offer, or (ii) the seller's submission of a market-based offer higher than its cost-based.

(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:

$$\text{Non-Performance Charge} = \text{Performance Shortfall} * \text{Non-Performance Charge Rate}$$

Where

For Capacity Performance Resources and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (365 / 30) / (the number of Real-Time Settlement Intervals in an hour) / (the number of Real-Time Settlement Intervals in an hour).

and for Base Capacity Resources the Non-Performance Charge Rate = (Weighted Average Resource Clearing Price applicable to the resource * (365 / 30) / (the number of Real-Time Settlement Intervals in an hour) / (the number of Real-Time Settlement Intervals in an hour).

(f) The Non-Performance Charges for each Capacity Performance Resource or

(including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. The total Non-Performance Charges for each Base Capacity Resource (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to the total payments due such Capacity Resource or Locational UCAP under section 5.14 of this Attachment DD for such Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.

(g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval, that provided energy or load reductions above the levels expected for such resource during such ~~hour~~ interval. For purposes of this provision, the performance expected of a resource, and the revenue distribution payment, if any, for a resource, shall be determined in accordance with the following formulae:

Formula 1: Market Participant Bonus Performance = Actual Performance – Expected Performance

And

Formula 2: Performance Payment = (Market Participant Bonus Performance / All Market Participants Bonus Performance) * Non-Performance Charge Revenues.

Where the result of Formula 1 is a positive number and where:

Actual Performance is as defined in subsection (c), provided, however, that Actual Performance for purposes of this calculation shall not exceed the megawatt level at which such resource was scheduled by the Office of the Interconnection during the Performance Assessment Intervals; and provided further that Actual Performance for a Market Participant that imports energy into the PJM Region during such Performance Assessment Interval shall be the net import, if any, from all interchange transactions scheduled by such Market Participant during such Performance Assessment Interval;

Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the resource's capacity obligation period, including, without limitation, a Base Capacity Demand Resource providing demand response during non-summer months; and

All Market Participants Bonus Performance is the sum of the results of calculating Formula 1 of this subsection (g) for all Market Participants that have Bonus Performance during such Performance Assessment Interval.

(h) The provisions of this section 10A shall apply during the 2016/2017 Delivery Year, provided that:

- (i) Non-Performance Charges shall be determined solely for and assessed solely on, Capacity Performance Resources committed for such Delivery Year;
- (ii) The Non-Performance Charge shall be 0.5 times the Non-Performance Charge calculated under subsection (e) hereof; and
- (iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.75 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(i) The provisions of this section 10A shall apply during the 2017-2018 Delivery Year, provided that:

- (i) Non-Performance Charges shall be determined solely for, and assessed solely on, Capacity Performance Resources committed for such Delivery Year;
- (ii) The Non-Performance Charge shall be 0.6 times the Non-Performance Charge calculated under subsection (e) hereof; and
- (iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.9 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(j) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year.

Section(s) of the
PJM Operating Agreement
(Marked / Redline Format)

3.1 Introduction.

This schedule sets forth the accounting and billing principles and procedures for the purchase and sale of services on the PJM Interchange Energy Market and for the operation of the PJM Region.

3.1A Revenue Data for Settlements

- (a) Revenue Data for Settlements are energy quantities used for accounting and billing and are determined based on data submitted by a Market Participant.
- (b) Once a Market Participant submits five-minute revenue meter data for a resource, the Market Participant must continue to provide revenue meter data for that resource on a five-minute basis.
- (c) For generation resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or hourly revenue meter data submitted to the Office of the Interconnection as adjusted in accordance with subsection (d). The revenue meter data for a generation resource can be either positive, representing energy injection, or negative, representing an energy withdrawal.
- (d) Revenue Data for Settlements for generation resources for which Market Participants submit hourly revenue meter data to the Office of the Interconnection shall be calculated as follows:
 - i) For each Real-time Settlement Interval, the Revenue Data for Settlements is equal to the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, as further described in the PJM Manuals for an hour ~~multiplied by plus an offset-scaling factor. The scaling factor is equal to the ratio of the hourly revenue meter data to the hourly integrated telemetry values or hourly integrated State Estimator values calculated according to section 2.3 of this Schedule. The offset is the difference between the hourly meter data value and (the hourly integrated telemetry or hourly integrated State Estimator value) times 12 and multiplied by absolute value of the ratio of (the Real-time Settlement Interval telemetry or State Estimator value) and (the absolute value of the sum of the Real-time Settlement Interval telemetry or State Estimator values for the hour).~~
 - ii) If the difference between the average of the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, and further described in the PJM Manuals, for an hour and the hourly revenue meter data is greater than 20 percent of the hourly revenue meter data and greater than 10 MW, then the Revenue Data for Settlements is a flat profile of the hourly revenue meter data equally apportioned over the five minute intervals in the hour.
 - iii) If a Market Participant is unable to provide telemetry for a generation resource, the Revenue Data for Settlements will be a flat profile of the hourly revenue meter data equally apportioned over the five-minute intervals in the hour.

(e) For all energy transactions for which telemetry is not available, the Revenue Data for Settlements is the submitted value to the Office of the Interconnection adjusted for any curtailment and flat profiled over the set of five-minute intervals that the energy transaction is scheduled and dispatched.

(f) For ~~D~~demand ~~R~~esponse resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or is the hourly revenue meter data submitted to the Office of the Interconnection and flat profiled over a set of dispatch intervals in the hour.

(g) For load, the Revenue Data for Settlements is the hourly submitted value to the Office of the Interconnection and flat profiled equally apportioned over the five-minute intervals in the hour.

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

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

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

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

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

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

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

3.2.2 Regulation.

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

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

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

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

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

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a

generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour, in accordance with the PJM Manuals and below.

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

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

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

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

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

(g) To determine the ~~performance~~-Regulation market ~~performance~~-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 ~~performance~~-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 ~~performance~~-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 ~~capability~~-clearing price for each Regulation Zone by subtracting the ~~performance~~-Regulation market ~~performance~~-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the ~~capability~~-Regulation market ~~capability~~-clearing price for that market Real-time Settlement Interval.

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

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

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

factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

The Office of the Interconnection shall calculate an 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:

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

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

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:

$$\text{Accuracy Score} = \text{max} ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

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

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the 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 Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller.

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

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

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate

in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations .

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

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

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

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

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

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

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

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

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

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

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

(f) A Market Seller'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 , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the 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 market-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) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement

Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

- 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the 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 Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
- 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(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 of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the

requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the 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 market-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 shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

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

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

Where:

h = the hours in the applicable Operating Day;

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

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

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

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

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

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

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

interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

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

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

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

(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 Dynamic Transfers to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller’s lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to

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

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

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 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:

$$\text{Ramp_Request}_t = \frac{(\text{UDS}_{\text{target}}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSL}_{\text{time}}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

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 for each Real-time Settlement Interval. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW for each Real-time Settlement Interval.

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

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

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

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

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

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

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

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

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

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

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

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

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

resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

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

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

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

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

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource *that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's*

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

3.2.3A Synchronized Reserve.

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

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

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

the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur in a Real-time Settlement Interval.

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

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

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

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

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

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

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

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

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

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

C = 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; and

D = 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where:

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;

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

C = 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; and

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

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

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

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption

achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

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

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves

and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a 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 Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

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

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

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource;

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-

ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJM Settlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJM Settlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the

“ending MW usage” (as defined above) and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the time of the “ending MW usage” in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

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

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the 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 market-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) $\{(URTLMP - UDALMP) \times DAG\}$, or (ii) $\{(URTLMP - UB) \times DAG\}$ 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 market-based schedule and the offer associated with that market-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 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 $\{(AG - LMP_{DMW}) \times (UB - URTLMP)\}$ where:

AG equals the actual output of the unit;

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

UB equals the unit offer for that unit for which output is increased, determined according to the 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 Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

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

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

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

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

in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to

provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) 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, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by On-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, except for the months of June through September in the Delivery Year, the following formula shall be used to measure an Emergency and Pre-Emergency Load Response participant's demand reductions when determining compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

- (a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.
 - i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:
 - 1. NERC holidays;
 - 2. Weekend days;
 - 3. Event days. For the purposes of this section an event day shall be either:
 - i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a

Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

- ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.
- iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

- i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:
 - 1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
 3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.
- ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.
 - iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to

section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

- i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

- ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\Delta \text{LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and ΔLMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully

specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) of this Schedule and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in section 1.10.1A(k) of this Schedule, and may

update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event the end-use customer's ~~hourly~~ energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount that the end-use customer's ~~hourly~~ energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$

and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;

RTL_{iz} is the real-time load for LSE i in zone z ;

X is the total export quantity from PJM in that hour; and

X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJM Settlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

- i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;
- ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;
- iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;
- iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;
- v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section

3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

- i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- ii. An Economic Load Response Participant's settlements pursuant to 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.
- iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.
 - i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.
 - ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately

reflect what the customer load would have been absent a load reduction.

- v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

Attachment B

PJM Open Access Transmission Tariff and PJM Operating Agreement

(Clean Format)

Section(s) of the
PJM Open Access Transmission Tariff
(Clean Format)

3.1 Introduction.

This schedule sets forth the accounting and billing principles and procedures for the purchase and sale of services on the PJM Interchange Energy Market and for the operation of the PJM Region.

3.1A Revenue Data for Settlements

- (a) Revenue Data for Settlements are energy quantities used for accounting and billing and are determined based on data submitted by a Market Participant.
- (b) Once a Market Participant submits five-minute revenue meter data for a resource, the Market Participant must continue to provide revenue meter data for that resource on a five-minute basis.
- (c) For generation resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or hourly revenue meter data submitted to the Office of the Interconnection as adjusted in accordance with subsection (d). The revenue meter data for a generation resource can be either positive, representing energy injection, or negative, representing an energy withdrawal.
- (d) Revenue Data for Settlements for generation resources for which Market Participants submit hourly revenue meter data to the Office of the Interconnection shall be calculated as follows:
 - i) For each Real-time Settlement Interval, the Revenue Data for Settlements is equal to the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, as further described in the PJM Manuals for an hour plus an offset. The offset is the difference between the hourly meter data value and (the hourly integrated telemetry or hourly integrated State Estimator value) times 12 and multiplied by absolute value of the ratio of (the Real-time Settlement Interval telemetry or State Estimator value) and (the absolute value of the sum of the Real-time Settlement Interval telemetry or State Estimator values for the hour).
 - ii) If the difference between the average of the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, and further described in the PJM Manuals, for an hour and the hourly revenue meter data is greater than 20 percent of the hourly revenue meter data and greater than 10 MW, then the Revenue Data for Settlements is a flat profile of the hourly revenue meter data equally apportioned over the five minute intervals in the hour.
 - iii) If a Market Participant is unable to provide telemetry for a generation resource, the Revenue Data for Settlements will be a flat profile of the hourly revenue meter data equally apportioned over the five-minute intervals in the hour.
- (e) For all energy transactions for which telemetry is not available, the Revenue Data for Settlements is the submitted value to the Office of the Interconnection adjusted for any curtailment and flat profiled over the set of five-minute intervals that the energy transaction is scheduled and dispatched.

- (f) For demand response resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or hourly revenue meter data submitted to the Office of the Interconnection and flat profiled over a set of dispatch intervals in the hour.

- (g) For load, the Revenue Data for Settlements is the hourly submitted value to the Office of the Interconnection and flat profiled equally apportioned over the five-minute intervals in the hour.

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

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

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

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

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

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

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

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

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

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

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

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a

generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour, in accordance with the PJM Manuals and below.

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

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

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

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

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

(g) To determine the Regulation market performance 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 Regulation market performance 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 Regulation market performance 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 Regulation market capability clearing price for each Regulation Zone by subtracting the Regulation market performance clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability clearing price for that market Real-time Settlement Interval.

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

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

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

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

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

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

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

where δ is delay.

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

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

The Office of the Interconnection shall calculate an 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:

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

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

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:

$$\text{Accuracy Score} = \text{max} ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

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

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the 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 Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller.

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

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

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

Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations .

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

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

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

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

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

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

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

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

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

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by

the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

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

(f) A Market Seller'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 , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the 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 market-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) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

- 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the 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 Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
- 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(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 of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to

a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the 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 market-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 shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

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

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

Where:

h = the hours in the applicable Operating Day;

A = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind

The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-Time Settlement Intervals for that hour. The summation of each Real-Time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviations;

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

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

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

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

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

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

total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

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

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

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

(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 Dynamic Transfers to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller’s lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to

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

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

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 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:

$$\text{Ramp_Request}_t = \frac{(\text{UDS}_{\text{target}}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSL}_{\text{atime}}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

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 for each Real-time Settlement Interval. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW for each Real-time Settlement Interval.

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

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

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

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

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

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

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

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

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

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

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

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

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

resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

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

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

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

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

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource *that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's*

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

3.2.3A Synchronized Reserve.

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

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

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

the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur in a Real-time Settlement Interval.

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

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

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

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

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

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

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

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

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

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

C = 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; and

D = 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where:

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;

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

C = 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; and

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

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

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

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption

achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

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

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves

and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a 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 Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

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

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

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource;

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-

ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJM Settlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJM Settlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the

“ending MW usage” (as defined above) and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the time of the “ending MW usage” in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

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

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the 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 market-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) $\{(URTLMP - UDALMP) \times DAG\}$, or (ii) $\{(URTLMP - UB) \times DAG\}$ 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 market-based schedule and the offer associated with that market-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 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 $\{(AG - LMP_{DMW}) \times (UB - URTLMP)\}$ where:

AG equals the actual output of the unit;

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

UB equals the unit offer for that unit for which output is increased, determined according to the 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 Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

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

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

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

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

in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to

provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) 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, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by on-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, except for the months of June through September in the Delivery Year, the following formula shall be used to measure an Emergency and Pre-Emergency Load Response participant's demand reductions when determining compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;
2. Weekend days;
3. Event days. For the purposes of this section an event day shall be either:
 - (i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - (ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer

locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

- ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

- iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

- i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.
 2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
 3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office

of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\Delta \text{LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and ΔLMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is

available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) of this Schedule and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in section 1.10.1A(k) of this Schedule, and may update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event that the end-use customer's energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount the end-use customer's energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$ and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;
 RTL_{iz} is the real-time load for LSE i in zone z ;
 X is the total export quantity from PJM in that hour; and
 X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJM Settlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;

v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

10A. CHARGES FOR NON-PERFORMANCE AND CREDITS FOR PERFORMANCE

(a) For the 2018/2019 Delivery Year and any subsequent Delivery Year (and for certain purposes for the 2016/2017 and 2017/2018 Delivery Years as provided in subsections (h) and (i) hereof), each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), and each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation or demand response resources that perform during such hour in excess of the level expected based on commitments (if any) of such resources.

(b) Performance shall be measured for purposes of this assessment during each Performance Assessment Interval.

(c) For each Performance Assessment Interval, the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource and Locational UCAP has fallen short of the performance expected of such committed Capacity Resource, and the magnitude of any such shortfall, based on the following formula:

Performance Shortfall = Expected Performance - Actual Performance

Where the result of such formula is a positive number and where:
Expected Performance =

for Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve a declared Emergency Action; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and Capacity Storage Resources: [(Resource Committed Capacity * the Balancing Ratio)];

where

Resource Committed Capacity = the total megawatts of Unforced Capacity of the Capacity Resource committed by such Capacity Market Seller or Locational UCAP Seller; and

The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports and Demand Response Bonus Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only

for any Performance Assessment Interval for which performance by any external Generation Capacity Resource would have helped resolve the Emergency Action that was the subject to the Performance Assessment Hour; and provided further that for any Delivery Year up to and including the 2019/2020 Delivery Year, Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

All Committed Generation and Storage Capacity = the total megawatts of Unforced Capacity of all Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and all Capacity Storage Resources committed by all Capacity Market Sellers, FRR Entities, Locational UCAP Sellers;

All Actual Generation Performance and Storage Resource Performance = the total amount of Actual Performance for all generation resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and storage resources during the interval;

Net Energy Imports = the sum of interchange transactions importing energy into PJM (not including those associated with external Generation Capacity Resources and therefore included in All Actual Generation Performance) minus the sum of interchange transactions exporting energy out of PJM, but not less than zero;

Demand Response Bonus Performance = the sum of Bonus performance provided by Demand Response resources as calculated in (g) below;

and for Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades: Resource Committed Capacity;

where

Resource Committed Capacity = the total megawatts of capacity committed from such Capacity Resource committed capacity without making any adjustment for the Forecast Pool Requirement

and

Actual Performance =

for each generation resource, the metered output of energy delivered by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each storage resource, the metered output of energy delivered by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each Demand Resource, the demand response provided by such resource, plus such resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval, as established through the PJM demand response settlement procedure consistent with the standards specified in Schedule 6 of the RAA;

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; and

for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Interval, and zero if it is not in service during such Performance Assessment Interval.

Such calculation shall encompass all resources located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment

Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval. For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Interval shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.

(d) Notwithstanding subsection (c) above, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, or was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the Interconnection, based on a determination by the Office of the Interconnection that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM Region. Such a resource shall be considered in the calculation of a Performance Shortfall if it otherwise was needed and would have been scheduled by the Office of the Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to: (i) any operating parameter limitations submitted in the resource's offer, or (ii) the seller's submission of a market-based offer higher than its cost-based.

(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:

$$\text{Non-Performance Charge} = \text{Performance Shortfall} * \text{Non-Performance Charge Rate}$$

Where

For Capacity Performance Resources and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (365 / 30) / (the number of Real-Time Settlement Intervals in an hour) / (the number of Real-Time Settlement Intervals in an hour).

and for Base Capacity Resources the Non-Performance Charge Rate = (Weighted Average Resource Clearing Price applicable to the resource * (365 / 30) / (the number of Real-Time Settlement Intervals in an hour) / (the number of Real-Time Settlement Intervals in an hour).

(f) The Non-Performance Charges for each Capacity Performance Resource or

(including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. The total Non-Performance Charges for each Base Capacity Resource (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to the total payments due such Capacity Resource or Locational UCAP under section 5.14 of this Attachment DD for such Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.

(g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval, that provided energy or load reductions above the levels expected for such resource during such interval. For purposes of this provision, the performance expected of a resource, and the revenue distribution payment, if any, for a resource, shall be determined in accordance with the following formulae:

Formula 1: $\text{Market Participant Bonus Performance} = \text{Actual Performance} - \text{Expected Performance}$

And

Formula 2: $\text{Performance Payment} = (\text{Market Participant Bonus Performance} / \text{All Market Participants Bonus Performance}) * \text{Non-Performance Charge Revenues}$.

Where the result of Formula 1 is a positive number and where:

Actual Performance is as defined in subsection (c), provided, however, that Actual Performance for purposes of this calculation shall not exceed the megawatt level at which such resource was scheduled by the Office of the Interconnection during the Performance Assessment Intervals; and provided further that Actual Performance for a Market Participant that imports energy into the PJM Region during such Performance Assessment Interval shall be the net import, if any, from all interchange transactions scheduled by such Market Participant during such Performance Assessment Interval;

Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the resource's capacity obligation period, including, without limitation, a Base Capacity Demand Resource providing demand response during non-summer months; and

All Market Participants Bonus Performance is the sum of the results of calculating Formula 1 of this subsection (g) for all Market Participants that have Bonus Performance during such Performance Assessment Interval.

(h) The provisions of this section 10A shall apply during the 2016/2017 Delivery Year, provided that:

- (i) Non-Performance Charges shall be determined solely for and assessed solely on, Capacity Performance Resources committed for such Delivery Year;
- (ii) The Non-Performance Charge shall be 0.5 times the Non-Performance Charge calculated under subsection (e) hereof; and
- (iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.75 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(i) The provisions of this section 10A shall apply during the 2017-2018 Delivery Year, provided that:

- (i) Non-Performance Charges shall be determined solely for, and assessed solely on, Capacity Performance Resources committed for such Delivery Year;
- (ii) The Non-Performance Charge shall be 0.6 times the Non-Performance Charge calculated under subsection (e) hereof; and
- (iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.9 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(j) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year.

Section(s) of the
PJM Operating Agreement
(Clean Format)

3.1 Introduction.

This schedule sets forth the accounting and billing principles and procedures for the purchase and sale of services on the PJM Interchange Energy Market and for the operation of the PJM Region.

3.1A Revenue Data for Settlements

- (a) Revenue Data for Settlements are energy quantities used for accounting and billing and are determined based on data submitted by a Market Participant.
- (b) Once a Market Participant submits five-minute revenue meter data for a resource, the Market Participant must continue to provide revenue meter data for that resource on a five-minute basis.
- (c) For generation resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or hourly revenue meter data submitted to the Office of the Interconnection as adjusted in accordance with subsection (d). The revenue meter data for a generation resource can be either positive, representing energy injection, or negative, representing an energy withdrawal.
- (d) Revenue Data for Settlements for generation resources for which Market Participants submit hourly revenue meter data to the Office of the Interconnection shall be calculated as follows:
 - i) For each Real-time Settlement Interval, the Revenue Data for Settlements is equal to the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, as further described in the PJM Manuals for an hour plus an offset. The offset is the difference between the hourly meter data value and (the hourly integrated telemetry or hourly integrated State Estimator value) times 12 and multiplied by absolute value of the ratio of (the Real-time Settlement Interval telemetry or State Estimator value) and (the absolute value of the sum of the Real-time Settlement Interval telemetry or State Estimator values for the hour).
 - ii) If the difference between the average of the five-minute telemetry values or State Estimator values calculated according to section 2.3 of this Schedule, and further described in the PJM Manuals, for an hour and the hourly revenue meter data is greater than 20 percent of the hourly revenue meter data and greater than 10 MW, then the Revenue Data for Settlements is a flat profile of the hourly revenue meter data equally apportioned over the five minute intervals in the hour.
 - iii) If a Market Participant is unable to provide telemetry for a generation resource, the Revenue Data for Settlements will be a flat profile of the hourly revenue meter data equally apportioned over the five-minute intervals in the hour.
- (e) For all energy transactions for which telemetry is not available, the Revenue Data for Settlements is the submitted value to the Office of the Interconnection adjusted for any curtailment and flat profiled over the set of five-minute intervals that the energy transaction is scheduled and dispatched.

- (f) For demand response resources, Revenue Data for Settlements may be five-minute revenue meter data submitted to the Office of the Interconnection or hourly revenue meter data submitted to the Office of the Interconnection and flat profiled over a set of dispatch intervals in the hour.

- (g) For load, the Revenue Data for Settlements is the hourly submitted value to the Office of the Interconnection and flat profiled equally apportioned over the five-minute intervals in the hour.

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

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

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

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

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

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

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

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

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

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

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

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a

generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour, in accordance with the PJM Manuals and below.

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

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

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

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

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

(g) To determine the Regulation market performance 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 Regulation market performance 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 Regulation market performance 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 Regulation market capability clearing price for each Regulation Zone by subtracting the Regulation market performance clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability clearing price for that market Real-time Settlement Interval.

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

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

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

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

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

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

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

where δ is delay.

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

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

The Office of the Interconnection shall calculate an 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:

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

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

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:

$$\text{Accuracy Score} = \text{max} ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

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

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the 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 Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller.

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

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

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

Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations .

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

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

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

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

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

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

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

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

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

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by

the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

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

(f) A Market Seller'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 , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the 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 market-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) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

- 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the 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 Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
- 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(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 of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to

a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the 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 market-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 shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

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

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

Where:

h = the hours in the applicable Operating Day;

A = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind

The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-Time Settlement Intervals for that hour. The summation of each Real-Time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviations;

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

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

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

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

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

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

total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

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

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

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

(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 Dynamic Transfers to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller’s lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to

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

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

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

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

(ii) real-time economic maximum \geq 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:

$$\text{Ramp_Request}_t = \frac{(\text{UDS}_{\text{target}}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSL}_{\text{atime}}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

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 for each Real-time Settlement Interval. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW for each Real-time Settlement Interval.

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

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

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

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

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

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

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

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

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

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

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

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

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

resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

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

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

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

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

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource *that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's*

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

3.2.3A Synchronized Reserve.

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

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

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

the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur in a Real-time Settlement Interval.

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

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

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

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

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

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

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

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

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

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

C = 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; and

D = 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where:

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;

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

C = 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; and

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

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

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

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption

achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

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

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves

and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a 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 Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

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

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

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource;

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-

ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJM Settlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJM Settlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the

“ending MW usage” (as defined above) and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the time of the “ending MW usage” in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

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

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the 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 market-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) $\{(URTLMP - UDALMP) \times DAG\}$, or (ii) $\{(URTLMP - UB) \times DAG\}$ 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 market-based schedule and the offer associated with that market-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 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 $\{(AG - LMP_{DMW}) \times (UB - URTLMP)\}$ where:

AG equals the actual output of the unit;

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

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

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

where $UB - URTLMP$ shall not be negative.

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

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

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

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

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

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

in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to

provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) 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, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by On-Site Generators pursuant to the provisions of Section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, except for the months of June through September in the Delivery Year, the following formula shall be used to measure an Emergency and Pre-Emergency Load Response participant's demand reductions when determining compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

- (a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.
 - i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:
 1. NERC holidays;
 2. Weekend days;
 3. Event days. For the purposes of this section an event day shall be either:
 - i) any weekday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a

Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

- ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.
- iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

- i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:
 - 1. Event days. For the purposes of this section an event day shall be either:
 - a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to Section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or
 - b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;
 3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.
- ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.
 - iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to Section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to Section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to Section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to

section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this Section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to Sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Section 1.5A shall be subject to the following provisions:

- i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

- ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where $(\Delta \text{LMP} \times \text{MWh consumed}) > (\text{LMP}_{\text{NEW}} \times \text{DR})$, where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and ΔLMP is the price before Economic Load Response is dispatched minus the LMP_{NEW} .

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully

specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in section 1.10.1A(k) of this Schedule and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in section 1.10.1A(k) of this Schedule, and may

update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, real-time operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event the end-use customer's energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount that the end-use customer's energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in section 3.2.3(o) of this Appendix, the Economic Load Response Participant shall be assessed balancing operating reserve charges in accordance with that section 3.2.3.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be $RTL_{iz}/(RTL + X)$

and the ratio share for party j shall be $X_j/(RTL + X)$.

Where:

RTL is the total real time load in all zones where $LMP \geq$ Net Benefits Test price;

RTL_{iz} is the real-time load for LSE i in zone z ;

X is the total export quantity from PJM in that hour; and

X_j is the export quantity by party j from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJM Settlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing operating reserves settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead operating reserves. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing operating reserve charge in accordance with section 3.2.3 of this Appendix. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as operating reserves pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to Sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of Section 3.3A.7(a) shall not be eligible for settlement pursuant to Sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this Section 3.3A.7(b) include, but are not limited to, the following:

- i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;
- ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;
- iii. Settlements based on On-Site Generator data if the On Site Generation is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;
- iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;
- v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of Section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of Section

3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

- i. An Economic Load Response Participant's registrations submitted pursuant to Section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- ii. An Economic Load Response Participant's settlements pursuant to 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).
- iii. An Economic Load Response Participant's settlements pursuant to Sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.
- iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing operating reserves charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the End-Use Customer's normal operations.
 - i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.
 - ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately

reflect what the customer load would have been absent a load reduction.

- v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring End-Use Customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this Section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.