Definitions – L – M – N

Market Suspension:

"Market Suspension" shall mean the inability of the Office of the Interconnection to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances, as further described in Operating Agreement, Schedule 1, section 1.10.8(d) and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.8(d), or the inability of the Office of the Interconnection to produce Zonal Dispatch Rates for a total of seven (7) or more Real-time Settlement Intervals within a clock hour, for the purposes of the Real-time Energy Market, as further described in Operating Agreement, Schedule 1, section 1.11.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.11.6.

1.10 Scheduling.

1.10.1 General.

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

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

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

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

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Operating Agreement, Schedule 1, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed $2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to $2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Operating Agreement, Schedule 1, section 1.12; and

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

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

(c–2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to $2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

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

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

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

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

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

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

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

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

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

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

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

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

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

$2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour;

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

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

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

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

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

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

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

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

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

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

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

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

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

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

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

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource’s offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the

Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in $/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be $0.02/MWh, and for the period from the second month after implementation through the second January 1 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource

which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a

Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

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

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

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic

Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such

offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for $0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

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

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

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

Where:

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

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

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

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to section 1.10.9 below or Operating Agreement, Schedule 1, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

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

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

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

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

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

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

1.10.3 Self-scheduled Resources.

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

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

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

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

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

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

1.10.4 Capacity Resources.

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

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

Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

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

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

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

1.10.6 External Market Buyers.

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

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

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

1.10.7 Bilateral Transactions.

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

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM

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

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

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Operating Agreement, Schedule 1, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above~~,~~, ~~no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.5.~~ it will be declared a Market Suspension, and Day-ahead Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.6.1. If the Office of the Interconnection declares a Market Suspension, it shall notify Market Participants of the Market Suspension as soon as practicable.

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

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

1.10.9 Hourly Scheduling.

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

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

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

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

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

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

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

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

1.10.9A Updating Offers in Real-time

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

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

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

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

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

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

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (9) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time.

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

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

1.11 Real-time Dispatch.

The Office of the Interconnection shall determine the least cost security constrained economic dispatch and send dispatch targets for each resource to Market Participants. The least cost security constrained economic dispatch is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on forecasted operating conditions on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1*,* section 1.7.6) as described in the PJM Manuals and on the offers for energy and ancillary services at which Market Sellers have entered as described by Operating Agreement, Schedule 1, section 1.10 and Operating Agreement, Schedule 1, section 2.4 and on offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market.

(a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6), the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints.

(b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.

(c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In performing the security constrained economic dispatch of the system, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program. The State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. 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. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, which shall provide the megawatt output of generators and the loads at buses in the PJM Region, transmission line losses, and actual flows or loadings on transmission facilities as defined in the PJM Manuals.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled or self-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled or self-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

As part of the real-time security constrained economic dispatch calculation, the Office of the Interconnection shall use submitted ramp rates to calculate the next dispatch point.

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time security constrained economic dispatch program or other operational reasons, the most recent State Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request, by following the Day-ahead Market clearing, or by following the direct request of the Market Seller, subject to the Office of the Interconnection's determination of actions necessary to maintain reliability.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection upon receipt.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Economic Load Response Participant resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response

Participant resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Economic Load Response Participant resources will be zero.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Economic Load Response Participant resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Economic Load Response Participant resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from available either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the Synchronized Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. The Office of the Interconnection shall clear both the Day-ahead Synchronized Reserve Market and the Real-time Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Synchronized Reserve Market. Resources shall be cleared to provide Synchronized Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Synchronized Reserve offer and the product substitution cost of providing Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy, and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product..

(c) Synchronized Reserve Events will be initiated by the Office of the Interconnection by approving the latest solved intelligent reserve deployment (IRD) case in the real-time security constrained economic dispatch application. When initiating a Synchronized Reserve Event, the Office of the Interconnection shall dispatch generation resources and direct the deployment of Economic Load Response Participant resources for Synchronized Reserve by transmitting Synchronized Reserve instructions to generation resources and Economic Load Response Participant resources through approval of the latest available IRD case solution in the real-time security constrained economic dispatch application, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice. In the event the IRD case is not available (as described in Tariff, Attachment K-Appendix, Sections 1.11(b) and (c)), manual Synchronized Reserve deployment will be utilized, in accordance with PJM Manuals.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.001. PJMSettlement shall be the Counterparty to the purchases and sales of Non-Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from pool-scheduled generation resources as needed to ensure the Primary Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Resources providing Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Non-Synchronized Reserve Market and the Real-time Non-Synchronized Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market, and the offers submitted in the Non-Synchronized Reserve Market. Resources eligible to sell Non-Synchronized Reserve shall be cleared to provide Non-Synchronized Reserve on the basis of each resource's product substitution cost between providing Non-Synchronized Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement.

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation resources from which Non-Synchronized Reserve is available, in accordance with the PJM Manuals. Market Sellers shall comply with Non-Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Non-Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4C Secondary Reserve.

(a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants.

(b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response

Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

(c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

1.11.6 Real-time Energy Market Suspension.

If the Office of the Interconnection declares a Market Suspension (the inability of the Office of the Interconnection to produce Zonal Dispatch Rates for a total of seven (7) or more Real-time Settlement Intervals within a clock hour), Real-time Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.5.2 and the Office of the Interconnection shall notify Market Participants of the Market Suspension as soon as practicable.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine Locational Marginal Prices based on the least costly means of obtaining energy to serve the next increment of load and meet reserve requirements (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the network model and each Interface Pricing Point between PJM and an adjacent Control Area, based on the forecasted operating conditions and the submitted energy offers as described in Operating Agreement, Schedule 1, section 2.4. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the applicable reserve requirements. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange. The process for the determination of Real-time Prices occurs in the Real-time Price software program, and is known as the pricing run for the Real-time Energy Market. The Real-time Price software program uses the input data from the latest approved real-time security constrained economic dispatch solution with a target time at the end of the current five-minute interval as described in the PJM Manuals and performs the same optimization as the real-time security constrained economic dispatch program but additionally applies Integer Relaxation to Eligible Fast-Start Resources. The real-time security constrained economic dispatch program, which is considered the dispatch run for the Real-time Energy Market, performs a real-time joint optimization of energy and reserves, given operating conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any monitored transmission constraints that may exist.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants, Pre-Emergency Load Response participants and Emergency Load Response participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Operating Agreement, Schedule 1, section 2.4, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified Real-time Energy Market offers from Economic Load Response Participants, Emergency Load Response and Pre-Emergency Load Response.

(c) In performing the Real-time Price calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as described in Operating Agreement, Schedule 1, section 2.4 as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative), including Transmission Constraint Penalty Factors, associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The Real-time Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints, and marginal loss impact.

(d) During the Operating Day, the calculation set forth in Operating Agreement, Schedule 1, section 2.5 shall be performed every five minutes, using the Office of the Interconnection's Real-time Price software program, producing the Real-time Prices for the current five minute interval based on forecasted system conditions and the latest approved PJM security-constrained economic dispatch solution with a target time at the end of the current five minute interval. If no security-constrained economic dispatch solution was approved for the target time at the end of the current five minute interval, the Locational Marginal Price program will use the most recently approved security-constrained economic dispatch solution with a target time prior to the end of the Locational Marginal Price program five minute interval. If a technical problem with or malfunction of the security-constrained economic dispatch or Locational Marginal Price software programs exists, including but not limited to program failures or data input failures, the Office of the Interconnection will utilize the best available RT SCED solution to calculate LMPs.

2.5.1 Declaration of Shortage Pricing

(a) The Office of the Interconnection shall use its Real-time Price software program, to determine if the Office of the Interconnection is experiencing a 30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage for the purposes of declaring shortage pricing as further described in the PJM Manuals. If all reserve requirements in every modeled Reserve Zone and Reserve Sub-zone can be met at prices less than or equal to the applicable Reserve Penalty Factor for those reserve requirements, Real-time Prices shall be calculated as described in Operating Agreement, Schedule 1, section 2.5 and no Reserve Penalty Factor(s) shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When the Real-time Price software determines that a 30-minute Reserve shortage, a Primary Reserve shortage and/or a Synchronized Reserve shortage exists, whereby the reserve requirement cannot be met at a price less than or equal to the applicable Reserve Penalty Factor(s) associated with a Reserve Zone or Reserve Sub-zone, the Office of Interconnection shall implement shortage pricing. During shortage pricing, the Real-time Prices shall be calculated by incorporating the applicable Reserve Penalty Factor(s) for the deficient reserve requirement as the lost opportunity cost impact of the deficient reserve requirement consistent with the determination of the clearing price for each reserve product, and the components of Locational Marginal Prices referenced in Operating Agreement, Schedule 1, section 2.5 above shall be calculated as described below. Shortage pricing shall exist until the Real-time Price software program is able to meet the specified reserve requirements and there is no Voltage Reduction Action or Manual Load Dump Action in effect.

(b) If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem, including but not limited to failures of data input into the Real-time Price software program, the Office of the Interconnection will utilize the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

(c) The Office of the Interconnection shall issue day-ahead alerts to PJM Members of the possible need to use emergency procedures during the following Operating Day. Such emergency procedures may be required to alleviate real-time emergency conditions such as a transmission emergency or potential reserve shortage. The alerts issued by the Office of the Interconnection may include, but are not limited to, the Maximum Emergency Generation Alert, Primary Reserve Alert and/or Voltage Reduction Alert. These alerts shall be issued to keep all affected system personnel informed of the forecasted status of the PJM bulk power system. The Office of the Interconnection shall notify PJM Members of all alerts and the cancellation thereof via the methods described in the PJM Manuals. The alerts shall be issued as soon as practicable to allow PJM Members sufficient time to prepare for such operating conditions. The day-ahead alerts issued by the Office of the Interconnection are for informational purposes only and by themselves will not impact price calculation during the Operating Day.

(d) The Office of the Interconnection shall issue a warning of impending operating reserve shortage and other emergency conditions in real-time to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM bulk power system. Such warnings will generally precede any associated action taken to address the shortage conditions. The Office of the Interconnection shall notify PJM Members of the issuance and cancellation of emergency procedures via the methods described in the PJM Manuals. The warnings that the Office of the Interconnection may issue include, but are not limited to, the Primary Reserve Warning, Voltage Reduction Warning, and Manual Load Dump Warning.

The purpose of the Primary Reserve Warning is to warn members that the available Primary Reserve may be less than the Primary Reserve Requirement. If the Primary Reserve shortage condition was determined as described above, the applicable Reserve Penalty Factor is incorporated into the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price as applicable.

The purpose of the Voltage Reduction Warning is to warn PJM Members that the available Synchronized Reserve may be less than the Synchronized Reserve Requirement and that a voltage reduction may be required. Following the Voltage Reduction Warning, the Office of the Interconnection may issue a Voltage Reduction Action during which it directs PJM Members to initiate a voltage reduction. If the Office of the Interconnection issues a Voltage Reduction Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, the Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minunte Reserve

Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Voltage Reduction Action has been terminated.

The purpose of the Manual Load Dump Warning is to warn members that dumping load may be necessary to maintain reliability. Following the Manual Load Dump Warning, the Office of the Interconnection may commence a Manual Load Dump Action during which it directs PJM Members to initiate a manual load dump pursuant to the procedures described in the PJM Manuals. If the Office of the Interconnection issues a Manual Load Dump Action for the Reserve Zone or Reserve Sub-Zone the Reserve Penalty Factors for the 30-minure Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement are incorporated in the calculation of the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price, Secondary Reserve Market Clearing Price, and Locational Marginal Price, as applicable and consistent with the provisions for determining those prices. The Reserve Penalty Factors for the 30-minure Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement will continue to be used in the Synchronized Reserve Market Clearing Price, Non-Synchronized Reserve Market Clearing Price and Locational Marginal Price calculation, as applicable and consistent with the provisions for determining those prices, until the Manual Load Dump Action has been terminated.

2.5.2 Declaration of Market Suspension

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Section 1.11.6, resources will be paid for their energy output and Real-time Prices shall be determined on an hourly basis and applied to each Real-time Settlement Interval in the following manner:

i) If the Market Suspension is less than or equal to six (6) consecutive hours, then the Real-time Prices associated with such Market Suspension shall be the average of Real-time Prices for each individual pricing node for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

ii) If the Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours and there are cleared Day-ahead Prices for the affected Operating Day, then the Real-time Prices associated with such Market Suspension shall be the Day-ahead Prices for each corresponding hour. If no such Day-ahead Prices exist, then the Real-time Prices shall be the average of the Real-time Prices for each individual pricing node for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

iii) If the Market Suspension is greater than twenty-four (24) consecutive hours, then the Real-time Prices associated with such Market Suspension shall be determined based on the construction of an aggregate supply curve.

The aggregate supply curve shall be established as follows:

For online resources operating on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used in the construction of the aggregate supply curve and for all market clearing and compensation.

For online resources operating on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension. The selected cost-based offer will be used in the construction of the aggregate supply curve and for all market clearing and compensation.

For available offline resources, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension for the construction of the aggregate supply curve.

The summation of the actual generation MWs for on-line resources will be used as a proxy for demand. The energy component of Locational Marginal Price will be determined hourly from the supply curve at the intersection of supply and demand where the impact of constraints is not considered. The loss and congestion component of Locational Marginal Price will be set to zero dollars per megawatt-hour.

Self-scheduled resources will be included in the supply stack but with a zero dollar per megawatt-hour offer price, and will not be eligible to set price. Off-line resources and resources directed to lower their output to Economic Minimum will not be eligible to set price. Generation resources that may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability will not be eligible to set price.

2.6 Calculation of Day-ahead Prices.

(a) The Office of the Interconnection shall use day-ahead security constrained economic dispatch optimization software to determine the least-costly means of obtaining energy to serve the next increment of load and meet day-ahead scheduling reserve requirements in the PJM Region, based on model flows and system conditions resulting from the load specifications, offers for generation as described in Operating Agreement, Schedule 1, section 2.4A, dispatchable load, Increment Offers, Decrement Bids, Up-to Congestion Transactions, offers for demand reductions, offers for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, and interchange transactions submitted to the Office of the Interconnection and scheduled in the Day-ahead Energy Market. Day-ahead economic dispatch is performed in the day-ahead security constrained economic dispatch software program, known as the dispatch run. Day-ahead Prices are calculated in a subsequent execution of the day-ahead security constrained economic dispatch optimization software program, known as the pricing run. The pricing run executes the same optimization as the dispatch run but additionally applies Integer Relaxation to Eligible Fast-Start Resources.

The Day-ahead Energy Market uses a multistage solution. The first stage, Resource Scheduling and Commitment (RSC) solves for an initial unit commitment with a limited set of constraints. The second stage solves with a more complete set of constraints/contingencies and performs the Three Pivotal Supplier test. The third stage, Scheduling Pricing and Dispatch, optimizes the dispatch and calculates final Day-ahead Energy Market prices.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-ahead Energy Market and shall be the basis for purchases and sales of energy and Transmission Congestion Charges resulting from the Day-ahead Energy Market. This calculation shall be made for each hour in the Day-ahead Energy Market by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, increment offers, import transactions, and/or has offered to decrease consumption by an Economic Load Response Participant resource, Decrement Bid, export transaction or price sensitive demand bid, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission line losses. The day-ahead Locational Marginal Prices at a bus shall be determined through the joint optimization program based on the lowest marginal cost to serve the next increment of load at the bus taking into account resource constraints, transmission constraints, marginal loss impact, and the impact of the applicable Operating Reserve Demand Curves. When the marginal energy megawatts is provided by converting a megawatts of reserves into a megawatts of energy, the resulting Locational Marginal Price takes into account the opportunity cost of that exchange.

(b) The Office of the Interconnection shall use its day-ahead market clearing software to forecast if the Office of the Interconnection will experience a shortage of the 30-minute Reserve Requirement, Extended 30-minute Reserve Requirement, the Primary Reserve Requirement, Extended Primary Reserve Requirement, the Synchronized Reserve Requirement, and/or the Extended Synchronized Reserve Requirement, as further described in the PJM Manuals. If the day-ahead market clearing software forecasts that a shortage of any of the reserve requirement(s) exists, the Office of the Interconnection shall implement shortage pricing through the inclusion of the applicable Reserve Penalty Factor(s) in the Day-ahead Locational Marginal Prices consistent with the determination of the clearing price for each reserve product. Shortage pricing shall exist until the day-ahead market clearing software is able to meet the specified reserve requirements.

2.6.1 Declaration of Market Suspension

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Section 1.10.8(d), Day-ahead Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Price of zero dollars per megawatt-hour and all settlements will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

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 Operating Agreement, Schedule 1, section 2.

(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 Operating Agreement, Schedule 1, section 3.1A 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 below, 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 in the Real-time Price software program, which is known as the pricing run, 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 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Operating Agreement, Schedule 1, section 1.10.1A(e).

(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 Economic Load Response Participant 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 Economic Load Response Participant 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. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

The Office of the Interconnection shall calculate 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:

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

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

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

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

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

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

(l) During a Market Suspension where the suspension is less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than twenty-four (24) consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource's Regulation clearing cost is determined by the summation of their Regulation offer and opportunity cost. The opportunity cost will be based on the resource's cost-based offer and will be determined as follows:

For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.

For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation accuracy score cannot be calculated during a Market Suspension, the 100-hour rolling average accuracy score will be used for the Market Suspension period.

(ii) If the regulation mileage ratio cannot be calculated during a Market Suspension, the mileage ratio will be set to one (1) for the Market Suspension period.

(iii) If the unit-specific benefits factor cannot be calculated during a Market Suspension, the unit-specific benefits factor would be based on the historical average unit-specific benefits factor over past hours that shared the same penetration of Regulation D resources that exist for the given Market Suspension hour.

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 Operating Agreement, Schedule 1, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

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

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

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

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

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 below do not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Reserve Requirements, 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 market. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

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

Except as provided in section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve credit.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Operating Reserve credit shall be reduced by the greater of zero or the difference of the resource's Day-ahead Operating Reserve Target and the Balancing Operating Reserve Target, as determined below.

A resource's Day-ahead Operating Reserve Target shall be determined in accordance with the following equation:

(A + B) - C

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's Balancing Operating Reserve Target shall be determined in accordance with the following equation:

D – (E + F)

Where:

D = the sum of Start-up Costs and No-load Costs and the incremental cost of energy summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

F = the sum of all revenues earned for providing Day-ahead Scheduling Reserves, Synchronized Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.

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 Operating Agreement, Schedule 1, 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 Operating Agreement, Schedule 1, section 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, 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 Tariff, Schedule 6A. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

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

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

Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant 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 the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Secondary 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 Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, 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 LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

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

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

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

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

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

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, 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 LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-5) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

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

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-5)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-5)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section 3.2.3(f-4), plus any cancellation fees paid in accordance with Operating Agreement, Schedule 1, 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 Tariff, Schedule 6A, 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 Operating Agreement, Schedule 1, section 1.12 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 Operating Agreement, Schedule 1, section 3.1A 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 Tariff, Schedule 6A.

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) below, 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, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, 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.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary 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, Secondary 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, Secondary 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, Secondary 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 Operating Agreement, Schedule 1, 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 Operating Agreement, Schedule 2, 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 Operating Agreement, Schedule 1, 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 Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, 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 11:00 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 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

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

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

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

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

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

$$Ramp\_Request_t = {(Dispatchtarget_{t-1} - AOutput_{t-1})}\big/{(LAtime_{t-1})}$$

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

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal 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 dispatch signal or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the dispatch signal 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 dispatch 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 dispatch signal, 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 – dispatch 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 dispatch 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 – dispatch LMP Desired MWh.

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

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – dispatch 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 Response Participant 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 Operating Agreement, Schedule 1, section 3.3A. 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 Operating Agreement, Schedule 1, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, 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. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, section 1.11.6, the Office of the Interconnection shall allocate the charges to the ratio share of real-time load plus export transactions.

(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 exceeds 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 Operating Agreement, Schedule 1, section 3.2.3(h)(ii)(A) 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, OVEC 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 Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, 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, Operating Agreement, Schedule 2 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, Operating Agreement, Schedule 2, 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 Operating Agreement, Schedule 1, section 6.4.3. 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's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide..

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized

Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Market Clearing Prices exist, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Market Clearing Price to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

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 Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement, the Primary Reserve Requirement, and the Synchronized Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) 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.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve 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) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be 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 energy dispatch 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.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. 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 energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead 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. 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 energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's energy expected output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time

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

(A x B) - C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, capped at the amount of Synchronized Reserve the resource responded during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and 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 to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or 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 to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A] plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The 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 energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time 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 multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The 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 energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$$(A + B + C + D) - (E + F + G + H)$$

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) A generation resource or Demand Resource will be credited for the assigned and/or self-scheduled amount of Tier 2 Synchronized Reserve, less any applicable Tier 2 Synchronized Reserve shortfall, multiplied by the Synchronized Reserve Market Clearing Price for each Real-Time Settlement Interval, in which they were assigned and/or self-scheduled. In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the PJM calculated expected response of Synchronized

Reserve in response to a Synchronized Reserve Event, the generation resource or Demand Resource will have a Tier 2 Synchronized Reserve shortfall and be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The Tier 2 Synchronized Reserve shortfall amount will be the difference between the lesser of the assigned plus self-scheduled amount or the PJM-calculated expected response and the actual response provided. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. The Tier 2 Synchronized Reserve shortfall amount is for all Real-time Settlement Intervals the generation resource or Demand Resource was assigned and/or self-scheduled Synchronized Reserve real-time on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a generation resource or Demand Resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for 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 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple Demand Resources that were assigned or self-scheduled to provide 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 Demand Resource that provided more Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other Demand Resources that provided less 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 Synchronized Reserve credited to each individual Demand Resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide 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 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. 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 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 an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Economic Load Response Participant 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 Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant 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 or increased by the amount the megawatt output of the generation resource differs from 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 but will be capped. If the generation resource has an assignment and the PJM-calculated expected response is greater than the assigned, then the megawatt output will be capped at the difference of the PJM-calculated expected response and the assigned. If the generation resource has no assignment, then the megawatt output will be capped at the PJM-calculated expected response. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant 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 Economic Load Response Participant 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 Economic Load Response Participant resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant 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's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Non-Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Non-Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Non-Synchronized Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Non-Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Non-Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Non-Synchronized Reserve Market Clearing Prices exist, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the Non-Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning Non-Synchronized Reserves.

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 Real-time Non-Synchronized Reserve Market Clearing Price shall be sum of the Reserve Penalty Factors for the 30-minute Reserve Requirement and the Primary Reserve Requirement for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the Primary Reserve Requirement shall be $850/MWh.

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

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve 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) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non- Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time 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 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary 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 ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary 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. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating

Days, and there are cleared Day-ahead Secondary Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Market Clearing Prices exist, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary Reserve Market Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the sum of the Reserve Penalty Factors for the Minimum 30-minute Reserve Requirements for each Reserve Zone or Reserve Sub-zone to which it can contribute.

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to reserve 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 Reserve Penalty Factor for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be 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 energy dispatch 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.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. 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 energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead 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. 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 energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [energy use for providing synchronous condensing multiplied by A] plus [the applicable condense start-up cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and 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 to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or 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 to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The 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 energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time 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 multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The 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 energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional energy use in excess of day-ahead energy use for providing synchronous condensing in real-time multiplied by A plus [any applicable condense start-up costs due to additional condense start-ups in real-time in excess of day-ahead condense start-ups allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero,

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B) – (C + D + E + F)

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

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 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the

Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing Secondary Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

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 Operating Agreement, Schedule 1, 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 for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(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 Operating Agreement, Schedule 1, section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, 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 in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

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

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

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, 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 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 applicable 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 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 Real-time 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 Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

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 $850/MWh, 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 Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, 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 Operating Agreement, section 14 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.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in section 5.2.1(b), each FTR Holder shall receive as a Transmission Congestion Credit a proportional share of the Day-ahead Energy Market Transmission Congestion Charges collected for each constrained hour.

(b) If an Effective FTR Holder between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in section 7 of this Schedule 1) and had a Virtual Transaction portfolio which includes Increment Offer(s), Decrement Bid(s), and/or Up-to Congestion Transaction(s) that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market, whereby the Effective FTR Holder's Virtual Transaction portfolio resulted in (i) a difference in Location Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses which is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, and (ii) an increasing the value between such delivery and receipt buses, then the Market Participant shall not receive any Transmission Congestion Credit associated with such Financial Transmission Right in such hour, that is attributable to the absolute value (i.e., the product of the constraint's shadow price times the distribution factor (dfax) of the difference between the Financial Transmission Right delivery and receipt buses) of the relevant Day-ahead Energy Market binding constraint (as further discussed in section 5.2.1(c) below), but no more than the excess of one divided by the number of hours in the applicable period multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction (i.e., FTR profit). For the purposes of this calculation, every individual Financial Transmission Right of an Effective FTR Holder shall be considered.

(c) For purposes of section 5.2.1(b), an Effective FTR Holder's Virtual Transaction portfolio shall be considered if the absolute value of the attributable net flow across a Day-ahead Energy Market binding constraint relative to the Day-ahead Energy Market load weighted reference bus between the Financial Transmission Right delivery and receipt buses exceeds the physical limit of such binding constraint by the greater of 0.1 MW or ten percent.

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

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Operating Agreement, Schedule 1, section 7.

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

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

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

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

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this

Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

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

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

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

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

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

Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Operating Agreement, Schedule 1, section 7.4.2 and in accordance with the following:

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

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

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

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

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Operating Agreement, Schedule 1, section 5.2.2(f) of this Schedule.

(h) Reserved.

5.2.3 Target Allocation of Transmission Congestion Credits.

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

During a Market Suspension where there are no Day-ahead Prices available for the affected Operating Day, the aforementioned Day-ahead Congestion Price will be substituted with the hourly integrated Real-time Congestion Price as determined in Operating Agreement, Schedule 1, section 2.5.

For a Market Suspension where the suspension is greater than twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are no Day-ahead Prices available for the affected Operating Day, the Day-ahead Financial Transmission Right Target Allocation values would be equal to zero for the hours corresponding to this suspension interval.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the Day-ahead Energy Market Transmission Congestion Charges in each hour. If the total of the Target Allocations is less than or equal to the total of the Day-ahead Energy Market Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Day-ahead Energy Market Transmission Congestion Charges shall be distributed as described below in Operating Agreement, Schedule 1, section 5.2.6 "Distribution of Excess Congestion Charges."

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

(c) At the end of a Planning Period if all FTR Holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR Holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to Operating Agreement, Schedule 1, section 7.4.4(c) and shall be allocated to all FTR Holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

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

monthly excess ARR revenues and excess Day-ahead Energy Market Transmission Congestion Charges for the Planning Period]}.

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

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

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Day-ahead Energy Market Transmission Congestion Charges accumulated in a month shall be distributed to each FTR Holder in proportion to, but not more than, any deficiency in the share of Day-ahead Energy Market Transmission Congestion Charges received by the FTR Holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Day-ahead Energy Market Transmission Congestion Charge distribution described in Operating Agreement, Schedule 1, section 5.2.6(a) is performed, any excess Day-ahead Energy Market Transmission Congestion Charges remaining at the end of a month shall be distributed to each FTR Holder in proportion to, but not more than, any deficiency in the share of Day-ahead Energy Market Transmission Congestion Charges received by the FTR Holder during the current Planning Period, including previously distributed excess Day-ahead Energy Market Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

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

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

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

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

5.2.7 Allocation of Balancing Congestion Charges

At the end of each hour during an Operating Day, the Office of the Interconnection shall allocate the Balancing Congestion Charges to real-time load and exports on a pro-rata basis. Such allocation shall not include purchases of Direct Charging Energy.

During a Market Suspension where the suspension has no Day-ahead Prices or if the suspension is less than or equal to twenty-four (24) hours, which may span up to two Operating Days, and there are no Day-ahead Prices available for the affected Operating Day, for each hour corresponding to this suspension interval, the Office of the Interconnection shall allocate the Balancing Congestion Charges to Financial Transmission Right Target Allocation values before being allocated to real-time load and exports on a pro-rata basis.

5.6 Transmission Constraint Penalty Factors

5.6.1 Application of Transmission Constraint Penalty Factors in the Day-ahead and Real-time Energy Markets

In the Day-ahead Energy Market, the Transmission Constraint Penalty Factors shall be used to ensure a feasible market clearing solution but not used to determine the Marginal Value of a transmission constraint. In the Real-time Energy Market, the Office of the Interconnection shall use Transmission Constraint Penalty Factors to determine the Marginal Value for a transmission constraint when that transmission constraint cannot be managed within the binding transmission limit in a dispatch interval. If a Market Suspension greater than twenty-four (24) consecutive hours is declared in the Real-time Energy Market as per Operating Agreement, Schedule 1, section 2.5.2, Transmission Constraint Penalty Factors shall not be used to determine the Marginal Value of a transmission constraint. The Marginal Value of the transmission constraint shall be used in the determination of the Congestion Price component of Locational Marginal Price as referenced in Tariff, Attachment K-Appendix, section 2.5 through Tariff, Attachment K-Appendix, section 2.6, and the parallel provisions of Operating Agreement, Schedule 1, section 2.5 through Operating Agreement, Schedule 1, section 2.6. The Transmission Constraint Penalty Factor may set the Marginal Value of the transmission constraint during any dispatch interval in the Real-time Energy Market depending on the following:

(a) If the market clearing software that clears the Real-time Energy Market cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval at a cost less than or equal to the Transmission Constraint Penalty Factor, the Transmission Constraint Penalty Factor shall set the Marginal Value of the transmission constraint. In such instances, to manage the flow over the constraint, the Office of the Interconnection may adjust the Transmission Constraint Penalty Factor as set forth in Tariff, Attachment K-Appendix, section 5.6.3 and the parallel provisions of Operating Agreement, Schedule 1, section 5.6.3.

(b) If the Real-time Energy Market constraints are subject to market-to-market congestion management protocols with an adjacent Regional Transmission Organization and the market clearing software cannot produce a solution that manages the flow on a constraint within the binding limit in a dispatch interval, the Office of the Interconnection may coordinate with such Regional Transmission Organization to either allow the Transmission Constraint Penalty Factor to set the Marginal Value of the transmission constraint or to apply the Constraint Relaxation Logic upon mutual agreement in accordance with applicable Joint Operating Agreements.

5.6.2 Default Transmission Constraint Penalty Factor Values

Transmission constraints located within the metered boundaries of the PJM Region, including market-to-market coordinated constraints, regardless of voltage level, are defaulted to a $30,000/MWh Transmission Constraint Penalty Factor in the Day-ahead Energy Market when determining the day-ahead security constrained economic dispatch, known as the dispatch run, and $2,000/MWh in the determination of Day-ahead Prices in the pricing run. Constraints located within the metered boundaries of the PJM Region, excluding market-to-market coordinated constraints, regardless of voltage level, are defaulted to a $2,000/MWh Transmission Constraint Penalty Factor in the Real-time Energy Market. Market-to-market coordinated constraints in the Real-time Energy Market, located within the metered boundaries of the PJM Region, will use a default Transmission Constraint Penalty Factor of $1,000/MWh or a value agreed upon by PJM and the relevant Regional Transmission Organization in accordance with applicable Joint Operating Agreements.

5.6.3 Modifications to Transmission Constraint Penalty Factor Values

(a) The Office of the Interconnection may modify the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market or Day-ahead Energy Market for individual transmission constraints to: (1) ensure the market clearing solution is feasible, (2) reflect changes to the operating practices which are mutually agreed upon with the neighboring RTO for managing such constraints for market-to-market coordinated constraints, or (3) reflect persistent system operational or reliability needs and the cost of the resources available to effectively relieve congestion on the constraint. When such conditions occur, the Office of the Interconnection may raise the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint cannot be provided by available resources at a cost below the default Transmission Constraint Penalty Factor. The Office of the Interconnection may lower the Transmission Constraint Penalty Factor when sufficient congestion relief on the constraint can be provided by available resources at a cost below the default Transmission Constraint Penalty Factor in order to prevent a high cost resource that cannot provide material congestion relief on the constraint from inappropriately setting price for the constraint. In either instance, to effectively relieve congestion on the constraint, the revised Transmission Constraint Penalty Factor value may be determined using the following formula, while accounting for the ability for such inputs to vary as system conditions change throughout the operating day:

$$\text{Revised Transmission Constraint Penalty Factor (\$/MW)} = \frac{\text{System Energy Price + Loss Price + Congestion Price (all binding constraints) – Incremental Energy Offer*}}{D_{fax}}$$

Where D_{fax} equals the distribution factor of the resource for the transmission constraint

*For purposes of this equation only, Incremental Energy Offer includes start up and no load costs where appropriate.

(b) The Office of the Interconnection shall post, as soon as practicable, on its website any changes to the default Transmission Constraint Penalty Factor values used in the Real-time Energy Market and/or the Day-ahead Energy Market.

6.4 Offer Price Caps.

6.4.1 Applicability.

(a) If, at any time, it is determined by the Office of the Interconnection in accordance with Sections 1.10.8 or 6.1 of this Schedule that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the offer prices for energy from such resource shall be capped as specified below. For such generation resources committed in the Day-ahead Energy Market, if the Office of the Interconnection is able to do so, such offer prices shall be capped for the entire commitment period, and such offer prices will be capped at a cost-based offer in accordance with section 6.4.2 and committed at the market-based offer or cost-based offer which results in the lowest overall system production cost. For such generation resources committed in the Real-time Energy Market such offer prices shall be capped at a cost-based offer in accordance with section 6.4.2 and dispatched on the market-based offer or cost-based offer which results in the lowest dispatch cost in accordance with 6.4.1(g) until the earlier of: (i) the resource is released from its commitment by the Office of the Interconnection; (ii) the end of the Operating Day; or (iii) the start of the generation resource's next pre-existing commitment.

The offer on which a resource is committed shall initially be determined at the time of the commitment. If any of the resource's Incremental Energy Offer, No-load Cost or Start-Up Cost are updated for any portion of the offer capped hours subsequent to commitment, the Office of the Interconnection will redetermine the level of the offer cap using the updated offer values. The Office of the Interconnection will dispatch the resource on the market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

Resources that are self-scheduled to run in either the Day-ahead Energy Market or in the Real-time Energy Market are subject to the provisions of this section 6.4. The offer on which a resource is dispatched shall be used to determine any Locational Marginal Price affected by the offer price of such resource and as further limited as described in Operating Agreement, Schedule 1, section 2.4 and Operating Agreement, Schedule 1, section 2.4A.

In accordance with section 6.4.1(h), a generation resource that is offer capped in the Real-time Energy Market but released from its commitment by the Office of the Interconnection will be subject to the three pivotal supplier test and further offer capping, as applicable, if the resource is committed for a period later in the same Operating Day.

(b) The energy offer price by any generation resource requested to be dispatched in accordance with Section 6.3 of this Schedule shall be capped at the levels specified in Section 6.4.2 of this Schedule. If the Office of the Interconnection is able to do so, such offer prices shall be capped only during each hour when the affected resource is so scheduled, and otherwise shall be capped for the entire Operating Day. Energy offer prices as capped shall be used to determine any Locational Marginal Price affected by the price of such resource.

(c) Generation resources subject to an offer price cap shall be paid for energy at the applicable Locational Marginal Price.

(d) [Reserved for Future Use]

(e) Offer price caps under section 6.4 of this Schedule shall be suspended for a generation resource with respect to transmission limit(s) for any period in which a generation resource is committed by the Office of the Interconnection for the Operating Day or any period for which the generation resource has been self-scheduled where (1) there are not three or fewer generation suppliers available for redispatch under subsection (a) that are jointly pivotal with respect to such transmission limit(s), and (2) the Market Seller of the generation resource, when combined with the two largest other generation suppliers, is not pivotal ("three pivotal supplier test"). In the event the Office of the Interconnection system is unable to perform the three pivotal supplier test for a Market Seller, generation resources of that Market Seller that are dispatched to control transmission constraints will be dispatched on the resource's market-based offer or cost-based offer which results in the lowest dispatch cost as determined in accordance with section 6.4.1(g).

(f) For the purposes of conducting the three pivotal supplier test in subsection (e), the following applies:

(i) All megawatts of available incremental supply, including available self-scheduled supply for which the power distribution factor ("dfax") has an absolute value equal to or greater than the dfax used by the Office of the Interconnection's system operators when evaluating the impact of generation with respect to the constraint ("effective megawatts") will be included in the available supply analysis at costs equal to the cost-based offers of the available incremental supply adjusted for dfax ("effective costs"). The Office of the Interconnection will post on the PJM website the dfax value used by operators with respect to a constraint when it varies from three percent.

(ii) The three pivotal supplier test will include in the definition of the relevant market incremental supply up to and including all such supply available at an effective cost equal to 150% of the cost-based clearing price calculated using effective costs and effective megawatts and the need for megawatts to solve the constraint.

(iii) Offer price caps will apply on a generation supplier basis (i.e. not a generating unit by generating unit basis) and only the generation suppliers that fail the three pivotal supplier test with respect to any hour in the relevant period will have their units that are dispatched with respect to the constraint offer capped. A generation supplier for the purposes of this section includes corporate affiliates. Supply controlled by a generation supplier or its affiliates by contract with unaffiliated third parties or otherwise will be included as supply of that generation supplier; supply owned by a generation supplier but controlled by an unaffiliated third party by contract or otherwise will be included as supply of that third party.

A generation supplier's units, including self-scheduled units, are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal.

(iv) In the Day-ahead Energy Market, the Office of the Interconnection shall include price sensitive demand, Increment Offers and Decrement Bids as demand or supply, as applicable, in the relevant market.

(g) In the Real-time Energy Market, the schedule on which offer capped resources will be placed shall be determined using dispatch cost, where dispatch cost is calculated pursuant to the following formulas:

Dispatch cost for the applicable hour = ((Incremental Energy Offer @ Economic Minimum for the hour [$/MWh] * Economic Minimum for the hour [MW]) + No-load Cost for the hour [$/H])

(i) For resources committed in the Real-time Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost at the time of commitment,

where:

Total Dispatch cost = Sum of hourly dispatch cost over a resource's minimum run time [$] + Start-Up Cost [$]

(ii) For resources operating in real-time pursuant to a day-ahead or real-time commitment, and whose offers are updated after commitment, the resource is dispatched on the offer with the lowest dispatch cost for the each of the updated hours.

(iii) However, once the resource is dispatched on a cost-based offer, it will remain on a cost-based offer regardless of the determination of the cheapest schedule.

(h) A generation resource that was committed in the Day-ahead Energy Market or Real-time Energy Market, is operating in real time, and may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, will be offer price capped, subject to the outcome of a three pivotal supplier test, for each hour the resource operates beyond its committed hours or Minimum Run Time, whichever is greater, or in the case of resources self-scheduled in the Real-time Energy Market, for each hour the resource operates beyond its first hour of operation, in accordance with the following provisions.

(i) If the resource is operating on a cost-based offer, it will remain on a cost-based offer regardless of the results of the three pivotal supplier test.

(ii) If the resource is operating on a market-based offer and the Market Seller fails the three pivotal supplier test then the resource will be dispatched on the cheaper of its market-based offer or the cost-based offer representing the offer cap as determined by section 6.4.2, whichever results in the lowest dispatch cost as determined under section 6.4.1(g).

(iii) If the Market Seller passes the three pivotal supplier test and the resource is currently operating on a market-based offer then the resource will remain on that offer, unless the Market Seller elects to not have its market-based offer considered for dispatch and to have only the cost-based offer that represents the offer cap level as determined under section 6.4.2 considered for dispatch in which case the resource will be dispatched on its cost-based offer for the remainder of the Operating Day.

(i) If the Office of the Interconnection declares a Market Suspension, in accordance with Operating Agreement, Schedule 1, section 1.11.6 and section 2.5.2, and such Market Suspension is greater than twenty-four (24) consecutive hours, the Office of the Interconnection shall use only cost-based offers for all resources for all market clearing and compensation, regardless of whether a Market Seller fails the three pivotal supplier test.

6.4.2 Level.

(a) The offer price cap shall be one of the amounts specified below, as specified in advance by the Market Seller for the affected unit:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in an offer price cap that reflects reasonably contemporaneous competitive market conditions for that unit;

(ii) For offers of \$2,000/MWh or less, the incremental operating cost of the generation resource as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals ("incremental cost"), plus up to the lesser of 10% of such costs or \$100 MWh, the sum of which shall not exceed \$2,000/MWh; and, for offers greater than \$2,000/MWh, the incremental cost of the generation resource;

(iii) For units that are frequently offer capped ("Frequently Mitigated Unit" or "FMU"), and for which the unit's market-based offer was greater than its cost based offer, the following shall apply:

(a) For units that are offer capped for 60% or more of their run hours, but less than 70% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10% or (ii) incremental cost plus \$20 per megawatt-hour;

(b) For units that are offer capped for 70% or more of their run hours, but less than 80% of their run hours, the offer price cap will be the greater of either (i) incremental cost plus 10%, or (ii) incremental cost plus $30 per megawatt-hour;

(c) For units that are offer capped for 80% or more of their run hours, the offer price cap will be the greater of either (i) incremental costs plus 10%; or (ii) incremental cost plus $40 per megawatt-hour.

(b) For purposes of section 6.4.2(a)(iii), a generating unit shall qualify for the specified offer cap upon issuance of written notice from the Market Monitoring Unit, pursuant to Section II.A of the Attachment M-Appendix, that it is a "Frequently Mitigated Unit" because it meets all of the following criteria:

(i) The unit was offer capped for the applicable percentage of its run hours, determined on a rolling 12-month basis, effective with a one month lag.

(ii) The unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) are less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.)

(iii) No portion of the unit is included in a FRR Capacity Plan or receiving compensation under Part V of the Tariff.

(iv) The unit is internal to the PJM Region and subject only to PJM dispatch.

(c) Any generating unit, without regard to ownership, located at the same site as a Frequently Mitigated Unit qualifying under Sections 6.4.2(a)(iii) shall become an "Associated Unit" upon issuance of written notice from the Market Monitoring Unit pursuant to Section II.A of Attachment M-Appendix, that it meets all of the following criteria:

1. The unit has the identical electric impact on the transmission system as the FMU;

2. The unit (i) belongs to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU or (ii) is regularly dispatched by PJM as a substitute for the FMU

based on differences in cost that result from the currently applicable FMU adder;

3. The unit (i) has an average daily cost-based offer, as measured over the preceding 12-month period, that is less than or equal to the FMU's average daily cost-based offer adjusted to include the currently applicable FMU adder or (ii) is regularly dispatched by PJM as a substitute for the FMU based on differences in cost that result from the currently applicable FMU adder.

The offer cap for an associated unit shall be equal to the incremental operating cost of such unit, as determined in accordance with Schedule 2 of the Operating Agreement and the PJM Manuals, plus the applicable percentage adder or dollar per megawatt-hour adder as specified in Section 6.4.2(a)(iii)(a), (b), or (c) for the unit with which it is associated.

(d) Market Participants shall have exclusive responsibility for preparing and submitting their offers on the basis of accurate information and in compliance with the FERC Market Rules, inclusive of the level of any applicable offer cap, and in no event shall PJM be held liable for the consequences of or make any retroactive adjustment to any clearing price on the basis of any offer submitted on the basis of inaccurate or non-compliant information.

6.4.3 Verification of Cost-Based Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based energy offer for a generation resource that includes an Incremental Energy Offer greater than $1,000/megawatt-hour, then, in order for that offer to be eligible to set the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the Incremental Energy Offer component of such cost-based offer. For each Incremental Energy Offer segment greater than $1,000/megawatt-hour, the Office of the Interconnection shall evaluate whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with the following formula:

Maximum Allowable Incremental Cost ($/MWh segment in accordance with the following formula: @ MW) =

$$[(\text{Maximum Allowable Operating Rate}_i) – (\text{Bid Production Cost}_{i-1})] / (MW_i – MW_{i-1})$$

where

i = an offer segment within the Incremental Energy Offer, which is comprised of a pairing of price ($/MWh) and a megawatt quantity

Maximum Allowable Operating Rate ($/hour @ MW) =

$$[(\text{Heat Input}_i\ @\ MW_i) \times (\text{Performance Factor}) \times (\text{Fuel Cost})] \times (1 + A)$$

where

Heat Input = a point on the heat input curve (in MMBtu/hr), determined in accordance with PJM Manual 15, describing the resource's operational characteristics for converting the applicable fuel input (MMBtu) into energy (MWh) specified in the Incremental Energy Offer;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e, design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent; and

A = Cost adder, in accordance with section 6.4.2(a)(ii) of this Schedule.

Bid Production Cost (\$/hour @ MW) =
$[\sum_{i=1}^{n}(MW_i - MW_{i-1}) \text{ x}(P_i) - \frac{1}{2} \text{ x UBS x } (MW_i - MW_{i-1}) \text{ x } (P_i - P_{i-1})]$ + No-Load Cost

where

MW = the MW quantity per offer segment within the Incremental Energy Offer;

P = the price (in dollars per megawatt-hour) per offer segment within the Incremental Energy Offer;

UBS = Uses Bid-Slope = 0 for block-offer resources (i.e., a resource with an Incremental Energy Offer that uses a step function curve); and 1 for all other resources (i.e., resources with an Incremental Energy Offer that uses a sloped offer curve); and

If the price submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost then that offer segment shall be deemed verified and is eligible to set the applicable Locational Marginal Price. If the price submitted for the offer segment is greater than the Maximum Allowable Incremental Cost, then the Market Seller's cost-based offer for that segment and all segments at an equal or greater price are deemed not verified and are not eligible to set the applicable Locational Marginal Price and such offer shall be price capped at the greater of \$1,000/megawatt-hour or the offer price of the most expensive verified segment on the Incremental Energy Offer for the purpose of setting Locational Marginal Prices; provided however, such Market Seller shall be allowed to submit a challenge to a non-verification determination, including supporting documentation, to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals. Upon review of such documentation, the Office of the Interconnection may determine that the Market Seller's cost-based offer is verified and eligible to set the applicable Locational Marginal Price as described above.

(i) For the first incremental segment (i=1), when the MW in the segment is greater than zero, the first segment shall be screened as a block-loaded segment (UBS=0) as if there was a preceding MW_{i-1} of zero. The Maximum Allowable Incremental Cost calculation for the first incremental would use a preceding Bid Production Cost $_{i-1}$ (at zero MW) equal to the energy No-Load Cost.

(ii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and is the only bid-in segment to be verified, then the segment shall be deemed not verified and subject to the rules as described above.

(iii) For the first incremental segment (i=1), when the MW in the segment is equal to zero, and there are additional segments to be verified, then the first segment shall be deemed verified only if the second segment is deemed verified. If the second segment is deemed not verified, then the first segment shall also be deemed not verified and subject to the rules as described above.

(b) If an Economic Load Response Participant a cost-based demand reduction offer that includes incremental costs greater than or equal to $1,000/megawatt-hour, in order for that offer to be eligible to determine the applicable Locational Marginal Price as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate the incremental costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs; and

(ii) The end use customer's incremental costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection, and may not include shutdown costs.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental costs greater than or equal to $1,000/megawatt-hour, the

Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

6.4.3A Verification of Fast-Start Resource Composite Energy Offers Over $1,000/Megawatt-hour

(a) If a Market Seller submits a cost-based offer for a generation resource that is a Fast-Start Resource that results in a Composite Energy Offer that is greater than $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Office of the Interconnection shall apply a formulaic screen to verify the reasonableness of the offer components:

Incremental Energy Offer and No-load Cost components of each offer segment shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the test described in Operating Agreement, Schedule 1, section 6.4.3.

Start-Up Cost component shall be evaluated for whether it exceeds the reasonably expected costs for that resource by applying the following formula:

Start-Up Cost ($) = [[(Performance Factor) x (Start Fuel) x (Fuel Cost)] + Start Maintenance Adder + Additional Start Labor + Station Service Cost] x (1 +A)

Where:

Start Fuel = fuel consumed from first fire of start process to breaker closing plus fuel expended from breaker opening of the previous shutdown to initialization of the (hot) unit start-up, excluding normal plant heating/auxiliary equipment fuel requirements;

Fuel Cost = applicable fuel cost as estimated by the Office of the Interconnection at a geographically appropriate commodity trading hub, plus 10 percent;

Performance Factor = a scaling factor that is a calculated ratio of actual fuel burn to either theoretical fuel burn (i.e., design Heat Input) or other current tested Heat Input, which is determined annually in accordance with the Market Seller's PJM-approved Fuel Cost Policy under Operating Agreement, Schedule 2 and PJM Manual 15, reflecting the resource's actual ability to convert fuel into energy (normal operation is 1.0);

Start Maintenance Adder = an adder based on all available maintenance expense history for the defined Maintenance Period regardless of unit ownership. Only expenses incurred as a result of electric production qualify for inclusion. Only Maintenance Adders specified as $/Start, $/MMBtu, or $/equivalent operating hour can be included in the Start Maintenance Adder;

Start Additional Labor = additional labor costs for startup required above normal station manning levels; and

Station Service Cost = station service usage (MWh) during start-up multiplied by the 12-month rolling average off-peak energy prices as updated quarterly by the Office of the Interconnection.

A = cost adder, in accordance with Operating Agreement, Schedule 1, section 6.4.2(a)(ii).

(b) Should the submitted Incremental Energy Offer and No-load Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above for any segment, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices):

(i) the Incremental Energy Offer for each segment shall be capped at the lesser of the cap described above in Operating Agreement, Schedule 1, section 6.4.3 or the submitted Incremental Energy Offer; and

(ii) the amortized No-load cost shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(c) Should the submitted Start-Up Cost exceed the reasonably expected costs for that resource as calculated pursuant to subsection (a) above, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Start-Up Costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

(d) If an Economic Load Response Participant submits an offer to reduce demand for a Fast-Start Resource where the maximum segment of the resulting Composite Energy Offer exceeds $1,000/megawatt-hour, then, in order for that Composite Energy Offer to be eligible to set the applicable Locational Marginal Price under Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the Economic Load Response Participant must validate such costs with the end use customer(s) and, upon request, submit to the Office of the Interconnection supporting documentation demonstrating that the end-use customer's costs in providing such demand reduction are greater than $1,000/megawatt-hour in accordance with the following provisions:

(i) The supporting documentation must explain and support the quantification of the end-use customer's incremental costs and shutdown costs; and

(ii) The end use customer's incremental and shutdown costs shall include quantifiable cost incurred for not consuming electricity when dispatched by the Office of the Interconnection, such as wages paid without production, lost sales, damaged products that cannot be sold, or other incremental costs as defined in the PJM Manuals or as approved by the Office of the Interconnection.

If upon review of the supporting documentation for the Economic Load Response Participant's, cost-based offer by the Office of the Interconnection and the Market Monitoring Unit, the Office of the Interconnection and/or the Market Monitoring Unit determines that the offer was not reasonably supported by incremental and shutdown costs greater than or equal to $1,000/megawatt-hour, the Office of the Interconnection and/or the Market Monitoring Unit may refer the matter to the FERC Office of Enforcement for investigation.

Should the submitted shutdown cost exceed the reasonably supported costs for that resource, then for the determination of Locational Marginal Prices as described in Operating Agreement, Schedule 1, section 2.5 (for determining Real-time Prices) and Operating Agreement, Schedule 1, section 2.6 (for determining Day-ahead Prices), the shutdown costs shall be adjusted as described in Operating Agreement, Schedule 1, section 2.4 (Determination of Energy Offers Used in Calculating Real-time Prices) and Operating Agreement, Schedule 1, section 2.4A (Determination of Energy Offers Used in Calculating Day-ahead Prices).

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules.

(a) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on cost-based offers, which are always parameter limited. Such offers must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such cost-based offers ("parameter limited schedules") shall be considered in the commitment of a resource when the Market Seller does not pass the three pivotal supplier test, as further described in Operating Agreement, Schedule 1, section 6.4.1 and the parallel provisions in Tariff, Attachment K-Appendix, section 6.4.1.

(b) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on market-based offers conforming to parameter limitations ("parameter limited schedules"). Such market-based parameter limited schedules must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such market-based parameter limited schedules shall be considered in the commitment of a resource under the following circumstances:

(i) For Capacity Performance Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert, Hot Weather Alert, Cold Weather Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert for all, or any part, of an Operating Day.

(ii) For Base Capacity Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency during hot weather operations during the period of June 1 through September 30; (ii) issues a Maximum Generation Emergency Alert or Hot Weather Alert during hot weather operations during the period of June 1 through September 30; or (iii) schedules units based on the anticipation of a Hot Weather Alert, or a Maximum Generation Emergency or Maximum Generation Emergency Alert during hot weather operations during the period of June 1 through September 30, for all, or any part, of an Operating Day.

(c) For the 2014/2015 through 2017/2018 Delivery Years for Generation Capacity Resources other than Capacity Performance Resources, and the 2016/2017 through 2018/2019 Delivery Years for Generation Capacity Resources identified and committed in an FRR Capacity Plan, parameter limited schedules shall be defined for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts.

For the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, and for the 2016/2017 Delivery Year and subsequent Delivery Years for Capacity Performance Resources, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual unit on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts;

(vi) Maximum Run Time;

(vii) Start-up Time; and

(viii) Notification Time.

These unit-specific values shall apply for the generating unit unless it is operating pursuant to an exception from those values under subsection (i) hereof due to operational limitations that prevent the unit from meeting the minimum parameters. Throughout the analysis process, the Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's unit-specific parameter limited schedule values.

In order to make its determination of the unit-specific parameter limited schedule values for a unit, the Office of the Interconnection may request that the Capacity Market Seller provide to it and the Market Monitoring Unit certain data and documentation as further detailed in the PJM Manuals. Once the Office of the Interconnection has made a determination of the unit-specific parameter limited schedule values for a unit, those values will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed based on changed operational capabilities of the unit.

A Capacity Market Seller that does not believe its generating unit can meet the unit-specific values determined by the Office of the Interconnection due to actual operating constraints, and who desires to establish adjusted unit-specific parameters for those units may request adjusted unit-specific parameter limitations. Any such request must be submitted to the Office of the Interconnection by no later than the February 28 immediately preceding the first Delivery Year for which the adjusted unit-specific parameters are requested to commence. Capacity Market Sellers shall supply, for each generating unit, technical information about the operational limits to support the requested parameters, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's request for adjusted unit-specific parameter limited schedule values. After it has completed its evaluation of the request, the Office of the Interconnection shall notify the Capacity Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied, by no later than April 15. The effective date of the request, if approved by the Office of the Interconnection, shall be no earlier than June 1.

The operational limitations referenced in this section 6.6 shall be (a) physical operational limitations based on the operating design characteristics of the unit, or (b) other actual physical constraints, including those based on contractual limits, that are not based on the characteristics of the unit. In order for a contractual or other actual constraint to be deemed a physical constraint that can be reflected in its unit-specific parameter limits for a Generation Capacity Resource, the Capacity Market Seller must demonstrate that contractual or other actual constraint is not simply an economic decision but a physical restriction that could not be rectified among any commercial alternatives actually available to it.

(d) [Reserved]

(e) For the 2014/2015 through 2017/2018 Delivery Years, upon receipt of proposed revised parameter limited schedule values from the Market Monitoring Unit, prepared in accordance with the procedures for periodic review included in Tariff, Attachment M-Appendix, section II.B.1, the Office of the Interconnection shall file to revise the Parameter Limited Schedule Matrix in section 6.6(d) above accordingly. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file the values that it determines are appropriate.

(f) For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall calculate and provide to Market Sellers default values in accordance with Tariff, Attachment M-Appendix, section II.B. The default values set forth in the table in subsection (d) above shall apply for the referenced technology types unless a generating unit is operating pursuant to an exception from the default values under subsection (i) due to physical operational limitations that prevent the unit from meeting the minimum parameters, or any megawatts of the unit are committed as a Capacity Performance Resource in which case the unit-specific or adjusted unit-specific values for the generating unit determined by the Office of the Interconnection shall apply to all megawatts of the generating unit offered into the PJM energy markets. For generating units having the ability to operate on multiple fuels, Market Sellers may submit a parameter limited schedule associated with each fuel type.

(g) For the 2016/2017 Delivery Year and subsequent Delivery Years, the following additional parameter limits shall apply for Capacity Performance Resources, other than Capacity Storage Resources, submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Capacity Performance Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) The combined start-up and notification times shall not exceed 24 hours, except when a Hot Weather Alert or Cold Weather Alert has been issued;

(ii) When a Hot Weather Alert or Cold Weather Alert has been issued, combined start-up and notification times shall not exceed 14 hours;

(iii) When a Hot Weather Alert or Cold Weather Alert has been issued, notification time shall not exceed one hour; and,

(iv) When a Hot Weather Alert or Cold Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Capacity Performance Resource for both its market-based schedules and cost-based schedules.

Capacity Storage Resources that clear in a Reliability Pricing Model Auction shall, unless the Capacity Market Seller has requested for its Capacity Storage Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and notification time, and/or minimum down time, due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) Have combined start-up and notification times that shall not exceed one hour; and,

(ii) Have a minimum down time that shall not exceed one hour.

(h) For the 2018/2019 and 2019/2020 Delivery Years, the following additional parameter limits for Base Capacity Resources submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Base Capacity Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) Combined start-up and notification times shall not exceed 48 hours;

(ii) When a Hot Weather Alert has been issued, notification time shall not exceed one hour; and,

(iii) When a Hot Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Base Capacity Resource for both its market-based schedules and cost-based schedules.

(i) If a generating unit is or will become unable to achieve the default or unit-specific values determined by the Office of the Interconnection due to actual operating constraints affecting the unit, the Capacity Market Seller of that unit may submit a written request for an exception to the application of those values. Exceptions to the parameter limited schedule default or unit-specific values shall be categorized as either a one-time temporary exception, lasting 30 days or less; a period exception, lasting at least 31 days and no more than one year; or a persistent exception, lasting for at least one year.

(i) *Temporary Exceptions*. A temporary exception shall be deemed accepted without prior review by the Market Monitoring Unit or the Office of the Interconnection upon submission by the Market Seller of the generating unit of written notification to the Market Monitoring Unit and the Office of the Interconnection, at least one Business Day prior to the commencement of the exception, and shall automatically commence and terminate on the dates specified in such notification, which must be for a period of time lasting 30 days or less, unless the termination date is extended pending a request for a period exception or shortened due to a change in the physical conditions of the unit such that the temporary exception is no longer required. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection within three days following the commencement of the temporary exception its documentation explaining in detail the reasons for the temporary exception, and shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Failure to provide a timely response to such request for additional information shall cause the temporary exception to terminate the following day. The Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing of an early termination of a temporary exception due to changed physical conditions by no later than one Business Day prior to the early termination date. A temporary exception may only be requested one-time for the same physical or actual constraint since an operational constraint that may occur more than once should be the subject of a period exception request rather than multiple temporary exception requests.

In addition, if a Market Seller is unaware of the need for a period exception prior to the February 28 deadline for submitting such requests, the Market Seller may utilize the temporary exception process and seek to modify that exception pursuant to the process described below.

Modification of Temporary Exceptions. If, prior to the scheduled termination date the Market Seller determines that the temporary exception must persist for more than 30 days and the Market Seller wants to extend the period for which the exception applies, or if a Market Seller is unaware of the need for a period or persistent exception prior to the February 28 deadline for submitting such requests and the Market Seller has submitted a temporary exception request, it must submit to the Market Monitoring Unit and the Office of the Interconnection a written request to modify the temporary exception to become a period exception or a persistent exception, and provide detailed documentation explaining the reasons for the requested modification of the temporary exception. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period or persistent exception request, and if the exception requested is based on new physical operating limits for the unit for which some or all historical operating data is unavailable, the Market Seller may also submit technical information about the physical operational limits of the unit to support the requested parameters. Such Market Seller shall respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Such request shall be reviewed by the Market Monitoring Unit and must be evaluated by the Office of the Interconnection using the same standard utilized to evaluate period exception and persistent exception requests. Per Tariff, Attachment M-Appendix, section II.B, the Market Monitoring Unit shall evaluate the modification request and provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request. The Office of the Interconnection shall provide its determination whether the request complies with the Tariff and Manuals by no later than 20 Business Days from the date of the modification request. A temporary exception shall be extended and shall not terminate until the date on which the Office of the Interconnection issues its determination of the modification request.

(ii) *Period Exceptions and Persistent Exceptions*. Market Sellers must submit period exception and persistent exception requests to the Market Monitoring Unit and the Office of the Interconnection by no later than the February 28 immediately preceding the twelve month period from June 1 to May 31 during which the exception is requested to commence. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period exception or persistent exception request, and if the exception requested is based on new physical operational limits for the unit for which some or all historical operating data is unavailable, the generating unit may also submit technical information about the physical operational limits for exceptions of the unit to support the requested parameters. The Market Monitoring Unit shall evaluate such request in accordance with the process set forth in Tariff, Attachment M-Appendix, section II.B. A Market Seller (i) must submit a parameter limited schedule value consistent with an agreement with the Market Monitoring Unit under such process or (ii) if it has not agreed with the Market Monitoring Unit on the parameter limited schedule value, may submit its own value to the Office of the Interconnection and to the Market Monitoring Unit, by no later than April 8. Each exception request must indicate the expected duration of the requested exception including the termination date thereof. The proposed parameter limited schedule value submitted by the Market Seller is subject to approval of the Office of the Interconnection pursuant to the requirements of the Tariff and the PJM Manuals. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the exception request.

After it has completed its evaluation of the exception request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the exception request is approved or denied, by no later than April 15. The effective date of the exception, if approved by the Office of the Interconnection, shall be no earlier than June 1 of the applicable Delivery Year. The Office of the Interconnection's determination for an exception shall continue for the period requested and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

The Market Seller shall provide written notification to the Market Monitoring Unit and the Office of the Interconnection of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection in their evaluations of the Market Seller's request for a period or persistent exception. The Market Monitoring Unit shall provide written notification to the Office of the Interconnection and the Market Seller of any change to its determination regarding the exception request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice. The Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, of any change to its determination regarding the exception request, based on the material change in facts, by no later than 20 Business Days after receipt of the Market Seller's notice. If the Office of the Interconnection determines that the exception no longer complies with the Tariff or Manuals, the following parameter values shall apply to all megawatts of the generating unit offered into the PJM energy markets:

(1) for generating units for which no megawatts of the unit are commited as Capacity Performance Resources the default values specified in the Parameter Limited Schedule Matrix shall apply for the 2016/2017 through 2017/2018 Delivery years,

(2) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which no adjusted unit-specific values have been approved by PJM, the Base Capacity Resource unit-specific values determined by PJM shall apply for the 2018/2019 and 2019/2020 Delivery Years,

(3) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply for the 2016/2017 Delivery Year and subsequent Delivery Years,

(4) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which adjusted unit-specific values have been approved by PJM, the

Base Capacity Resource adjusted unit-specific values shall apply for the 2018/2019 and 2019/2020 Delivery Years, and

(5) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource and for which adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource adjusted unit-specific values shall apply for the 2016/2017 Delivery Year and subsequent Delivery Years.

(i) Notwithstanding the foregoing, the provisions of this section 6.6 shall only pertain to the Offer Data a Market Seller must submit to the Office of the Interconnection for its offers into the Day-ahead Energy Market, rebidding period that occurs after the clearing of the Day-ahead Energy Market and Real-time Energy Market, and do not affect or change in any way a Generation Owner's obligation under NERC Reliability Standards to notify the Office of the Interconnection of its actual or expected actual physical operating conditions during the Operating Day.

(k) Notwithstanding anything contrary herein, the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for a generating unit shall be applicable to that generating unit regardless whether there is a change in the owner, operator or Market Seller of the unit because the parameter limited schedule values for the unit are determined based on the physical limitations of the unit, which should not change merely based on a change in owners, operator or Market Seller. Because parameter limited schedule values attach to the generating unit and are not owned by a Market Seller of the unit, when there are multiple owners or Market Sellers for a generating unit, all owners and Market Sellers shall be bound by the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for the unit.

(l) The provisions of this section 6.6 only apply to Generation Capacity Resources, and not to Energy Resources.

7.3 Auction Procedures.

7.3.1 Role of the Office of the Interconnection.

Financial Transmission Rights auctions shall be conducted by the Office of the Interconnection in accordance with standards and procedures set forth in the PJM Manuals, such standards and procedures to be consistent with the requirements of this Schedule. PJMSettlement shall be the Counterparty to the purchases and sales of Financial Transmission Rights arising from such auctions, provided however, that PJMSettlement shall not be a contracting party to any subsequent bilateral transfers of Financial Transmission Rights between Market Participants. The conversion of an Auction Revenue Right to a Financial Transmission Right pursuant to this section 7 shall not constitute a purchase or sale transaction to which PJMSettlement is a contracting party. Any Financial Transmission Rights auctions conducted to liquidate a defaulting Member's Financial Transmission Rights portfolio shall be conducted by the Office of the Interconnection in accordance with the procedures set forth in section 7.3.9 below, and as may be further described in the PJM Manuals.

7.3.2 Notice of Offer.

A holder of a Financial Transmission Right wishing to offer the Financial Transmission Right for sale shall notify the Office of the Interconnection of any Financial Transmission Rights to be offered. Each Financial Transmission Right sold in an auction shall, at the end of the period for which the Financial Transmission Rights were auctioned, revert to the offering holder or the entity to which the offering holder has transferred such Financial Transmission Right, subject to the term of the Financial Transmission Right itself and to the right of such holder or transferee to offer the Financial Transmission Right in the next or any subsequent auction during the term of the Financial Transmission Right.

7.3.3 Pending Applications for Firm Service.

(a) [Reserved.]

(b) Financial Transmission Rights may be assigned to entities requesting Network Transmission Service or Firm Point-to-Point Transmission Service pursuant to Operating Agreement, Schedule 1, section 5.2.2 (e), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(e), only if such Financial Transmission Rights are simultaneously feasible with all outstanding Financial Transmission Rights, including Financial Transmission Rights effective for the then-current auction period. If an assignment of Financial Transmission Rights pursuant to a pending application for Network Transmission Service or Firm Point-to-Point Transmission Service cannot be completed prior to an auction, Financial Transmission Rights attributable to such transmission service shall not be assigned for the then-current auction period. If a Financial Transmission Right cannot be assigned for this reason, the applicant may withdraw its application, or request that the Financial Transmission Right be assigned effective with the start of the next auction period.

7.3.4 Weekend On-Peak, Weekday On-Peak, Off-Peak and 24-Hour Periods.

Weekend on-peak, weekday on-peak, off-peak and 24-hour Financial Transmission Rights will be offered in the annual , long-term,and monthly auctions. Weekend on-peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending 11:00 p.m. on Saturdays, Sundays, and holidays as defined in the PJM Manuals. Weekday on-peak Financial Transmission Rights shall cover the periods from 7:00 a.m. up to the hour ending at 11:00 p.m. on Mondays through Fridays, except holidays as defined in the PJM Manuals. Off-Peak Financial Transmission Rights shall cover the periods from 11:00 p.m. up to the hour ending 7:00 a.m. on all days. The 24-hour period shall cover the period from hour ending 1:00 a.m. to the hour ending 12:00 midnight on all days. Each bid shall specify whether it is for a weekend on-peak, weekday on-peak, off-peak, or 24-hour period.

7.3.5 Offers and Bids.

(a) Offers to sell and bids to purchase Financial Transmission Rights shall be submitted during the period set forth in Operating Agreement, Schedule 1, section 7.1.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.1.2, and shall be in the form specified by the Office of the Interconnection in accordance with the requirements set forth below.

(b) Offers to sell shall identify the specific Financial Transmission Right, by term, megawatt quantity and receipt and delivery points, offered for sale. An offer to sell a specified megawatt quantity of Financial Transmission Rights shall constitute an offer to sell a quantity of Financial Transmission Rights equal to or less than the specified quantity. An offer to sell may not specify a minimum quantity being offered. Each offer may specify a reservation price, below which the offeror does not wish to sell the Financial Transmission Right. Offers submitted by entities holding rights to Financial Transmission Rights shall be subject to such reasonable standards for the verification of the rights of the offeror as may be established by the Office of the Interconnection. Offers shall be subject to such reasonable standards for the creditworthiness of the offeror or for the posting of security for performance as the Office of the Interconnection shall establish.

(c) Bids to purchase shall specify the term, megawatt quantity, price per megawatt, and receipt and delivery points of the Financial Transmission Right that the bidder wishes to purchase. A bid to purchase a specified megawatt quantity of Financial Transmission Rights shall constitute a bid to purchase a quantity of Financial Transmission Rights equal to or less than the specified quantity. A bid to purchase may not specify a minimum quantity that the bidder wishes to purchase. A bid may specify receipt and delivery points in accordance with Operating Agreement, Schedule 1, section 7.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.2.2, and may include Financial Transmission Rights for which the associated Transmission Congestion Credits may have negative values. Bids shall be subject to such reasonable standards for the creditworthiness of the bidder or for the posting of security for performance as the Office of the Interconnection shall establish.

(d) Bids and offers shall be specified to the nearest tenth of a megawatt and shall be greater than zero. The Office of the Interconnection may require that a market participant shall not submit in excess of 5000 bids and offers for any single monthly auction, or for any single round of the annual auction, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to the start of the bidding period if possible. Where such notice is provided after the start of the bidding period, market participants shall be required within one day to reduce their bids and offers for such auction below 5000, and the bidding period in such cases shall be extended by one day.

7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the Office of the Interconnection will create a base Financial Transmission Rights power flow model that includes all outstanding Financial Transmission Rights that have been approved and confirmed for any portion of the month for which the auction was conducted and that were not offered for sale in the auction. The base Financial Transmission Rights model also will include estimated uncompensated parallel flows into each interface point of the PJM Region and estimated scheduled transmission outages.

(b) In accordance with the requirements of Operating Agreement, Schedule 1, section 7.5, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5, and subject to all applicable transmission constraints and reliability requirements, the Office of the Interconnection shall determine the simultaneous feasibility of all outstanding Financial Transmission Rights not offered for sale in the auction and of all Financial Transmission Rights that could be awarded in the auction for which bids were submitted. The winning bids shall be determined from an appropriate linear programming model that, while respecting transmission constraints and the maximum MW quantities of the bids and offers, selects the set of simultaneously feasible Financial Transmission Rights with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. In the event that there are two or more identical bids for the selected Financial Transmission Rights and there are insufficient Financial Transmission Rights to accommodate all of the identical bids, then each such bidder will receive a pro rata share of the Financial Transmission Rights that can be awarded.

(c) Financial Transmission Rights shall be sold at the market-clearing price for Financial Transmission Rights between specified pairs of receipt and delivery points, as determined by the bid value of the marginal Financial Transmission Right that could not be awarded because it would not be simultaneously feasible. The linear programming model shall determine the clearing prices of all Financial Transmission Rights paths based on the bid value of the marginal Financial Transmission Rights, which are those Financial Transmission Rights with the highest bid values that could not be awarded fully because they were not simultaneously feasible, and based on the flow sensitivities of each Financial Transmission Rights path relative to the marginal Financial Transmission Rights paths flow sensitivities on the binding transmission constraints. Financial Transmission Rights with a zero clearing price will only be awarded if there is a minimum of one binding constraint in the auction period for which the Financial Transmission Rights path sensitivity is non-zero. Financial Transmission Right Options with a market-clearing price less than one dollar will not be awarded.

7.3.7 Announcement of Winners and Prices.

Within two (2) Business Days after the close of the bid and offer period for an annual Financial Transmission Rights auction round, and within five (5) Business Days after the close of the bid and offer period for a monthly Financial Transmission Rights auction, the Office of the Interconnection shall post the winning bidders, the megawatt quantity, the term and the receipt and delivery points for each Financial Transmission Right awarded in the auction and the price at which each Financial Transmission Right was awarded unless circumstances beyond PJM's control prevent PJM from meeting the applicable deadline. Under such circumstances, PJM will post the auction results at the earliest possible opportunity. The Office of the Interconnection shall not disclose the price specified in any bid to purchase or the reservation price specified in any offer to sell. If the Office of the Interconnection discovers an error in the results posted for a Financial Transmission Rights auction (or a given round of the annual Financial Transmission Rights auction), the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the Business Day following the initial publication of the results of the auction or round of the annual auction. After this initial notification, if the Office of the Interconnection determines that it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the second Business Day following the initial publication of the results of that auction or round of the annual auction. Thereafter, the Office of the Interconnection must post any corrected results by no later than 5:00 p.m. of the fourth calendar day following the initial publication of the results of the auction or round of the annual auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

7.3.8 Auction Settlements.

All buyers and sellers of Financial Transmission Rights between the same points of receipt and delivery shall pay PJMSettlement or be paid by PJMSettlement the market-clearing price, as determined in the auction, for such Financial Transmission Rights.

For a Market Suspension where the suspension is greater than twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are no Day-Ahead Prices available for the affected Operating Day, the Financial Transmission Right auction costs would be zero in proportion to the number of hours of the Market Suspension in the Operating Day.

7.3.9 Addressing Defaulting Member's Financial Transmission Rights.

In the event a Member fails to meet creditworthiness requirements or make timely payments when due pursuant to the Operating Agreement or Tariff, the Office of the Interconnection shall, as soon as practicable after declaring the Member to be in default as provided in Operating Agreement, section 15.1.5, use reasonable efforts to initiate within two applicable auctions the following procedures to settle, liquidate or otherwise resolve each Financial Transmission Rights position held by the defaulting Member:

a) The Office of the Interconnection shall unilaterally terminate all of the defaulting Member's rights with respect to forward Financial Transmission Rights positions as of the date of the Member's default.

b) As to each Financial Transmission Rights position held by the defaulting Member immediately prior to the termination of the defaulting Member's rights under subsection (a) above, the Office of the Interconnection shall determine and execute an appropriate course of action for addressing such Financial Transmission Rights position, based on the specific circumstances of the default as determined by the Office of the Interconnection in exercise of its reasonable judgment, such as (1) liquidating the position by offering it for sale in an upcoming applicable Financial Transmission Rights auction, (2) liquidating the position by offering it for sale in an auction called and scheduled for the specific purpose of liquidating one or more positions held by the defaulting Member ("Special Auction"), (3) allowing the position to go to settlement, or (4) another course of action the Office of the Interconnection determines to be appropriate under the circumstances that is designed to minimize potential losses to PJM Members. The Office of the Interconnection will provide reasonable advance notice to PJM Members of the approach or course of action it has determined to be appropriate prior to implementing that approach or course of action. The Office of the Interconnection is not required to apply a single approach to the defaulting Member's entire Financial Transmission Rights portfolio, and may determine that the appropriate course of action for addressing a defaulting Member's portfolio includes a combination of the above approaches as applied to different positions within the defaulting Member's overall Financial Transmission Rights portfolio.

c) The Office of the Interconnection will seek to minimize the losses to PJM Members associated with settling, liquidating or otherwise resolving the defaulting Member's Financial Transmission Rights portfolio and may base its determination in subsection (b) above on several factors, including but not limited to, the following:

1) the Office of the Interconnection's assessment of which approach will provide the greatest degree of protection to the financial integrity of the PJM Markets;

2) the size of the defaulting Member's Financial Transmission Rights portfolio, both in absolute terms and relative to overall market volume;

3) the term of the Financial Transmission Rights positions held by the defaulting Member as considered for a single position or on a portfolio basis;

4) whether liquidation is feasible or not, and on what timeline, due to the cessation or curtailment of trading at PJM for all Financial Transmission Rights or a subset of Financial Transmission Rights positions;

5) prevailing market conditions, such as but not limited to market liquidity and volatility; and

6) timing of the default and the actions taken to address the default.

d) Special Auctions. The Office of the Interconnection shall administer each Special Auction provided for in subsection (b)(2) above according to the procedures set forth in the Tariff and PJM Manuals for FTR auctions to the extent appropriate in the Office of the Interconnection's sole discretion, and may adopt special rules for each Special Auction to accommodate the unique circumstances underlying the particular default and particular Financial Transmission Rights positions being liquidated, with the terms and conditions of such auction being determined with the goal of facilitating a successful auction in light of the particular positions to be auctioned, the prevailing market conditions for such open positions (including the depth, scope, and nature of participation in such markets), and such other factors as the Office of the Interconnection determines appropriate, including those factors enumerated in subsection (c) above. The Office of the Interconnection shall provide reasonable advance notice to FTR Participants of a Special Auction and the terms and conditions under which it will be conducted.

e) All liquidations made pursuant to subsection (b) above shall be for the account of the defaulting Member (and all amounts owed PJM in respect thereof shall be included in amounts owed by the defaulting Member as part of its default).

f) Notwithstanding subsections 7.3.9(a) and (b) above, the actual net charges or credits resulting from the defaulting Member's Financial Transmission Rights positions for which PJMSettlement acted as counterparty as calculated through the normal settlement processes shall be included in calculating the Default Allocation Assessment charges as described in Operating Agreement, section 15.2.2.

14B.1 Billing Procedure:

PJMSettlement shall issue bills and billing statements pursuant to the provisions in this section 14B on behalf of itself and as agent for the Office of the Interconnection, as applicable. Payment of bills pursuant to this section 14B shall be made for the benefit of PJMSettlement and the Office of the Interconnection, as applicable.

(a) Monthly Bills. By the fifth Business Day of each month, PJM Settlement, in its own name and as agent for the Office of the Interconnection, as applicable, shall issue a bill to Members and other entities for monthly activity and detailing the charges and credits for all services furnished under this Agreement, the PJM Tariff and any service or rate schedule during the preceding month ("billing month"), excluding amounts billed pursuant to weekly bills for activity during the preceding month.

(b) Weekly Bills. By 5:00 p.m. Eastern Prevailing Time each Tuesday (or Wednesday in the event that a Tuesday is a holiday), PJMSettlement, in its own name and as agent for the Office of the Interconnection, as applicable, will issue a weekly bill to Members and other entities for all activity for certain services furnished under this Agreement, the PJM Tariff and any service or rate schedule for the days of the billing month during the week ending the prior Wednesday. The services for which such weekly bills shall be issued are set forth in PJM Manual 29.

(c) Billing Statement. PJMSettlement, in its own name and as agent for the Office of the Interconnection, as applicable, shall provide Members and other entities with billing statements at the time of issuance of the monthly and weekly bills, reflecting, in the form and manner set forth in PJM Manuals, the Member's or other entity's activity during the billing month and amounts due, net of activity previously billed.

(d) Market Suspensions: For a Market Suspension that is less than or equal to 24 consecutive hours and where Day-ahead Prices and all data necessary to calculate the services is available in advance of the time needed for processing the bill, the timelines listed in subsections (a) and (b) shall apply. For all other Market Suspensions, billing activity as defined in subsection (b) will be included in a weekly bill that is issued at least five business days from the date on which PJM Settlement receives all data necessary to calculate the services included in the weekly bill for such Market Suspension. If there are no remaining weekly bills for the billing month associated with such Market Suspension, the billing activity as defined in subsection (b) will be billed in the next monthly bill that is issued at least five business days from the date on which PJM Settlement receives all data necessary to calculate the services. All other billing services for such Market Suspension will be billed within three calendar months after the calendar month that included such Market Suspension.