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November 1, 2013

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426-0001

Re: PJM Interconnection, L.L.C., Docket No. ER13- 297 -000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and the Commission's Regulations, 18 C.F.R. Part 35, PJM Interconnection, L.L.C. ("PJM") hereby submits for filing revisions to Sections 3.2.3A(j) of Schedule 1 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") and the parallel provisions of Attachment K-Appendix of the PJM Open Access Transmission Tariff ("Tariff")¹ to change how penalties are assessed to a resource that fails to provide the amount of Tier 2 Synchronized Reserve² it was assigned or self-scheduled to provide when a Synchronized Reserve Event occurs. This filing addresses recommendations made by Monitoring Analytics, LLC, PJM's Independent Market Monitor ("IMM"). As noted below, the revisions to Section 3.2.3A were overwhelmingly approved by PJM stakeholders by acclamation.

¹ Where PJM refers herein to provisions in Schedule 1 of the Operating Agreement, those references also are intended to encompass the identical, parallel provisions in Attachment K-Appendix of the Tariff.

² All capitalized terms that are not otherwise defined herein shall have the same meaning as they are defined in the Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA").

PJM also seeks approval for a clarifying revision to Section 1.7.19A of Schedule 1 of the Operating Agreement regarding the requirements for providing Synchronized Reserve, consistent with a prior Commission directive in its April 19, 2012 order in Docket No. ER09-1063-004.³ Because PJM didn't become aware of the ambiguity in Section 1.7.19A until after the stakeholder process for this filing concluded, stakeholder approval wasn't sought for these clarifying revisions. Nevertheless, they remain consistent with the intent of the proposal that PJM stakeholders approved by acclamation.

PJM requests that the Commission issue an order accepting the enclosed revisions by no later than December 31, 2013, sixty (60) days after the date of this filing, with an effective date of January 1, 2014.

I. Background and Stakeholder Process

Synchronized Reserve is supplied by non-emergency generation resources and Demand Resources in the PJM Region.⁴ All non-emergency generation resources that are on-line and providing energy are required to make themselves available to provide Tier 1 and Tier 2 Synchronized Reserve to the extent the resource is capable to provide the service.⁵ Market Participants are paid to make their resources available to provide Tier 1 and Tier 2 Synchronized Reserves.

³ See *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057 (2012) at P 205.

⁴ Emergency generation resources aren't required to provide Synchronized Reserve because such resources are only available during emergency conditions, whereas Synchronized Reserve must be carried at all times. During emergency conditions when emergency generation resources are called upon by PJM, they are called upon to provide their energy to the system and not to provide Synchronized Reserve

⁵ Operating Agreement, Schedule 1, Section 1.7.19A(a). The must-offer requirement for non-emergency generation resources to provide Synchronized Reserve was implemented at the direction of the Commission in response to the objections of several intervenors, including PJM's Independent Market Monitor, to PJM's proposed market rule changes in its shortage pricing compliance filing submitted on

Demand Resources can supply Synchronized Reserve but aren't required to do so for two primary reasons. First, Demand Resources do not have a must-offer requirement in any of PJM's energy, ancillary services or capacity markets. Second, all Demand Resources may not be capable of responding to a Synchronized Reserve Event in ten minutes.

Tier 1 Synchronized Reserve is "Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event."⁶ As further described in PJM Manual 11, "Tier 1 is comprised of all those resources on line following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event, or demand resources capable of reducing load within 10 minutes."⁷

Tier 2 Synchronized Reserve is "Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the

June 18, 2010 in Docket No. ER09-1063-004. See *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057 (2012) at P 205. The intervenors objected to PJM's failure to include a must-offer requirement in its pricing proposal. The IMM argued that if prices rise when reserves are short, absent a must-offer obligation, generators may try to trigger shortage pricing by declining to submit offers. Therefore, the IMM proposed that PJM be required to apply a must-offer requirement for units operating at PJM's discretion, in real-time, and not otherwise assigned *via* the hour-ahead Tier 2 assignment. *Id.* at PP 200-205, n.155. PJM's compliance filing, submitted on July 18, 2012 in Docket No. ER12-2262, was accepted by the Commission in a letter order issued on October 1, 2012.

⁶ Operating Agreement, Schedule 1, Section 3.2.3A(b)(i).

⁷ PJM Manual 11: Energy & Ancillary Services Market Operations, Revision 56, Effective November 29, 2012 ("PJM Manual 11"), Section 4.2.1, at p. 63.

Interconnection energy dispatch signals and instructions.”⁸ Tier 2 Synchronized Reserve may also be provided by Demand Resources “that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the office of the interconnection.”⁹ Stated another way,

Tier 2 consists of:

- that additional capacity that is synchronized to the grid and operating at a point that deviates from economic dispatch (including condensing mode) to provide additional spinning synchronized reserve not available from Tier 1 resources; and
- dispatchable load resources that have controls in place to automatically drop load in response to a signal from PJM.¹⁰

On average, PJM initiates a Synchronized Reserve Event, which initiates the calling of resources to fulfill their commitment and perform as required, approximately two times per month. Currently, the penalty for non-performance of a resource with a Tier 2 Synchronized Reserve commitment has two components. First, the resource forfeits Synchronized Reserve revenues for the amount of the resource’s shortfall during the event for the contiguous hours the resource was assigned Tier 2 Synchronized Reserve prior to and including the hour in which the non-performance occurred. Second, the resource incurs an obligation in the Synchronized Reserve market for the amount of the shortfall for three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event. This obligation can be

⁸ Operating Agreement, Schedule 1, Section 3.2.3A(b)(ii).

⁹ Operating Agreement, Schedule 1, Section 3.2.3A(b)(iii).

¹⁰ PJM Manual 11, Section 4.2.9, at p. 63.

met by self-providing the service with no compensation or by purchasing from the market at the market clearing price.¹¹

The IMM has expressed concern with resources committed to provide Synchronized Reserve that fail to meet their commitments. In the *2013 Quarterly State of the Market Report for PJM: January through June*, the IMM indicated as follows:

Compliance

Non-compliance in the Synchronized Reserve Market remains a problem. Non-compliance has two major components: failure to deliver cleared Tier 2 Synchronized Reserve MW during spinning events; and failure of nonemergency, generation resources capable of providing energy to provide a daily synchronized reserve offer.

The MMU has expressed increasing concern over noncompliance by Tier 2 synchronized reserve resources during spinning events since 2011. When synchronized reserve resources clear the Synchronized Reserve Market they are obligated to provide their full cleared Tier 2 MW in a spinning event. The MMU has observed a wide range of spinning event response levels, presented its data to PJM and urged PJM to take action to increase compliance rates. For spinning events in January through June, 2013, longer than 10 minutes, approximately half of the generation providers offering more than half of the cleared synchronized reserve complied at a rate of less than 70 percent of their committed synchronized reserve MW. For demand response providers the compliance rate was worse with approximately half of the providers and 75 percent of the committed synchronized reserve MW complying at less than a 70 percent rate. In April, 2013, PJM through its Operating Committee began to address this problem. Several possible remedies are proposed and under consideration. The must-offer requirement for synchronized reserve changes the market, the nature of offers, and the penalty for non-compliance.

¹¹ Operating Agreement, Schedule 1, Section 3.2.3A(j).

The Shortage Pricing changes introduced on October 1, 2012, included a must offer requirement for most generators under normal conditions, and an expanded set of generators under well-defined abnormal conditions related to peak load. For all hours, all on-line, non-emergency, generating resources that are providing energy and are capable of providing synchronized reserve are deemed available for Tier 1 and Tier 2 synchronized reserve and they must have an offer and be available for reserve. When PJM issues a Primary Reserve Warning, Voltage Reduction Warning, or Manual Load Dump Warning, all other non-emergency, generation capacity resources must have an offer and be available for reserve. PJM members were reminded of this rule change at the June 5, 2013 Operating Committee meeting and PJM directed the MMU to enforce it. As of June 30, 2013, a significant number of generators are noncompliant.

FERC Order 719 imposes a synchronized reserve must-offer requirement. The MMU recommends that PJM remove the distinction between Tier 1 and Tier 2 synchronized reserve, remove the ability of participants to offer MW of synchronized reserve capability, remove the ability of participants to make reserve unavailable, and automatically dispatch primary reserve co-optimized with energy. In the interim, PJM should enforce a must-offer requirement for synchronized reserve based on physical capability (with physical capability the default offer) and increase penalties for non-compliance during spinning events.¹²

Further, given the approval of increased participation by demand resources in the Synchronized Reserve Market from 25% to 33% as of November 29, 2012,¹³ coupled with historical instances of performance issues from both generation and demand

¹² See *2013 Quarterly State of the Market Report for PJM: January through June*, Section 9 “Ancillary Service Markets,” at p. 246, *citing 2011 State of the Market Report for PJM*, Volume II, Section 9, “Ancillary Service Markets” at pg. 250, a copy of which may be found on the IMM’s website at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013q2-som-pjm-sec9.pdf.

¹³ Prior to November 29, 2012, Demand Resources were limited to providing 25% of the Synchronized Reserve Requirement. See PJM Manual 11: Energy & Ancillary Services Market Operations, Revision 54, Effective October 1, 2012, Section 4.2.9, at p. 76 (“PJM Manual 11”). As of November 29, 2012, PJM and its stakeholders agreed to increase this limit to 33% of the Synchronized Reserve Requirement. See PJM Manual 11: Energy & Ancillary Services Market Operations, Revision 56, Effective November 29, 2012, Section 4.2.9, at p. 79.

resources,¹⁴ PJM determined that market rule changes were needed to ensure that resources participating in the market can provide this reliability service initially and continuously. Thus, PJM initiated a stakeholder process to evaluate the Synchronized Reserve Market qualification process and consider whether additional ongoing processes to validate the performance capability of resources were needed, and if so, develop such additional processes.

PJM determined that the current penalty for failure to perform of Tier 2 Synchronized Reserve is no longer adequate given changed market conditions. Currently, the penalty obligates a resource to provide either Tier 2 Synchronized Reserve and not receive compensation therefor, or purchase Tier 2 Synchronized Reserve from the market for three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event. This three day period was based on the average number of days between Synchronized Reserve Events when the market was implemented in 2002. The concept was that a resource could be assigned Tier 2 Synchronized Reserve for some period of time when no Synchronized Reserve Event occurs and therefore never be required to actually deliver the service. Thus, when a Synchronized Reserve Event does occur and the resource fails to provide the assigned quantity, the penalty was designed to require the resource to “buy back” that quantity for which it could have been compensated since the prior Synchronized Reserve Event. Today, however, the average period of time between Synchronized Reserve Events is approximately fifteen days. The result is that a

¹⁴ See PJM's Markets Report to the PJM Members Committee at slide 49, <http://www.pjm.com/~media/committees-groups/committees/mc/20131021-webinar/20131021-item-06a-markets-report.ashx>.

resource assigned Synchronized Reserve that fails to perform is subject to a penalty that does not begin to approximate the amount of the revenue it could have earned.

To address this issue, PJM and its stakeholders recognized that the market rules need to be revised to ensure resource performance consistent with reliability assignments. PJM educated stakeholders regarding the must-offer requirement for Synchronized Reserve resources, provided historical performance data for the past two years, and committed to provide timely performance reports following Synchronized Reserve Events.

The stakeholders agreed to revise the penalty structure for Tier 2 Synchronized Reserve for failure to perform, described in Section 3.2.3A(j) of Schedule 1 of the Operating Agreement, to:

- eliminate the “contiguous” hours requirement;
- incorporate a retroactive obligation to refund Tier 2 payments received in the amount of the shortfall for all of the hours the resource was assigned over the immediate past interval to better align with the revenues the resource received for days on which it failed to perform;
- change the interval duration for which the penalty will apply from three days to the average number of days between Synchronized Reserve Events as determined by an annual review of the prior two years, or, the number of days since resource last failed to provide amount of Tier 2 Synchronized Reserve assigned or self-scheduled to provide; and,
- credit the refunds collected to loads that pay for Tier 2 Synchronized Reserve.¹⁵

To illustrate the effect of PJM’s proposal, by way of example, assume that a 5 MW resource is assigned Tier 2 Synchronized Reserve for an average of 6 hours per

¹⁵ See Presentation to PJM Members Committee entitled “Tier 2 Synchronized Reserves Performance” dated October 24, 2013, <http://www.pjm.com/~media/committees-groups/committees/mc/20131024/20131024-item-03-sr-performance-presentation-updated.ashx>.

day, at an average clearing price of \$5/MWh. Assuming an average duration of 15 days between Synchronized Reserve Events, the resource would be paid $\$5 \times 6 \text{ hours} \times 5 \text{ MW} \times 15 \text{ days}$ for a total of \$2,250 between events. If the resource fails to perform under PJM's current market rules, and the average price and number of hours per day are the same during the penalty period, the penalty would be $3 \text{ days} \times 6 \text{ hours} \times 5 \text{ MW} \times \5 for a total of \$450. PJM's proposal that is the subject of this filing would require that the entire \$2,250 credited since the last Synchronized Reserve Event be refunded as the penalty for failure to perform.

Because the actual number of days between Synchronized Reserve Events can vary, PJM stakeholders were concerned that if the refund period was based on the actual number of days since the prior Synchronized Reserve Event, the penalty could either be very large if it had been a long time since the last event, or could be very small if it had only been a short time since the last event. PJM and its stakeholders therefore agreed to maintain the concept of penalizing resources based on the average time between Synchronized Reserve Events, such that market participants would have a level of certainty as to the penalty that would apply for a failure to perform up to the level of a Tier 2 assignment. As a result of the use of this rolling, two-year average time period, the timeframe of the required refund can be either greater than or less than the actual number of days since the prior Synchronized Reserve Event. For example, using the same conditions in the example above, if there were 10 days since the last Synchronized Reserve Event, the resource would have received \$1,500 in revenue since that last event, but the penalty would be \$2,250 based on the last 15 days of its Tier 2 revenue. Similarly, if there were 20 days since the last event, the resource would

have made \$3,000 since the last event, but the penalty would still be \$2,250 based on the 15-day average.

The time period of the refund is limited to the lesser of the average number of days between Synchronized Reserve Events, the 15-day average in this example, and the number of days since the last event where the same resource did not perform. This provision was included in order to prevent the occurrence of “overlapping” penalties. Therefore, if the average number of days between events is 15, and there are 16 or more days since the last event, the limitation will not take effect. However, if there are less than 15 days since the last event, say 10 days, and the resource failed to perform during the last event, then the resource is only penalized based on the revenue it received during the 10 days since the prior event when it did not perform. PJM and its stakeholders agreed that this provision achieves the right balance between the risk of non-performance by resources given the must-offer requirement to provide Tier 2 Synchronized Reserve, and providing the necessary incentive to respond with the assigned amount of Tier 2 Synchronized Reserve when called upon.

PJM will revise Sections 4.2.1, 4.2.4 and 4.2.12 of PJM Manual 11 and Section 6.3 of PJM Manual 28, consistent with the proposed revisions to Section 3.2.3A.

II. Proposed Revisions

A. Revisions to Section 3.2.3A

For the reasons detailed above, PJM proposes to revise Section 3.2.3A(j) of the Operating Agreement as follows:

3.2.3A Synchronized Reserve.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the

Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. -The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Internal Market Buyers based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.¹⁶

¹⁶ eTariff records OATT ATT K Appx Sec 3.2 and OA Schedule 1 Sec 3.2.

The intent of PJM's proposed revisions is to provide an incentive for resources with Tier 2 Synchronized Reserve commitments to perform as self-scheduled or assigned by removing the potential to profit from Synchronized Reserve assignments and then not performing consistent with those assignments.

B. Revisions to Section 1.7.19A

After stakeholder discussion of the proposed revisions to Section 3.2.3A, PJM became aware of specific language ambiguity in Section 1.7.19A(a) of Schedule 1 of the Operating Agreement, which provisions describe the requirements for providing Synchronized Reserve. Therefore, in addition to the proposed revisions to Section 3.2.3A, PJM submits revisions to clarify the relevant language contained in Section 1.7.19A of Schedule 1 of the Operating Agreement as follows:

Synchronized Reserve can~~shall~~ be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Section 2.5(d) below, all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.¹⁷

¹⁷ eTariff records OATT ATT K APPX Sec 1.7 and OA Schedule 1 Sec 1.7.

This revision is necessary to clarify that Demand Resources have the ability to supply Synchronized Reserve but aren't required to do so, for the reasons discussed above.¹⁸

PJM notes that the revisions to Section 1.7.19A are not substantive changes, but merely changes to clarify the direction of the Commission that the must-offer requirement to provide Synchronized Reserve only applies to non-emergency generation resources, per its April 19, 2012 order in Docket No. ER09-1063-004.¹⁹ For that reason, PJM did not seek stakeholder approval to make these corrections.

III. Stakeholder Process

The proposed revisions to Sections 1.7.19A and 3.2.3A of Schedule 1 of the Operating Agreement and the parallel provisions of Attachment K-Appendix of the Tariff were endorsed by the PJM Markets and Reliability Committee at its September 26, 2013 meeting by a sector-weighted vote of 3.6/5.0 in favor.²⁰ The PJM Members Committee, at its meeting held on October 24, 2013, endorsed the revisions to the Tariff and approved the revisions to the Operating Agreement by acclamation with two objections and sixteen abstentions.

IV. Effective Date

PJM requests that the Commission issue an order accepting the enclosed revisions by no later than December 31, 2013, with an effective date of January 1, 2014.

¹⁸ See discussion, *infra*, on p. 2 and n. 3.

¹⁹ See *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,057 (2012) at P 205.

²⁰ See Minutes of Markets and Reliability Committee posted at <http://www.pjm.com/~media/committees-groups/committees/mrc/20131024/20131024-item-01-draft-20130926-meeting-minutes.ashx>.

V. Description of Submittal

PJM encloses with this transmittal letter electronic versions of the revisions to the Tariff in both marked (showing the changes) and clean forms.

VI. Correspondence

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

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VII. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. Electronic service is permitted as of November 3, 2008, under the Commission's regulations²¹ pursuant to Order No. 714²² and the Commission's Notice of Effectiveness of Regulations issued on October 28, 2008, in Docket No. RM01-5-000. In compliance with these regulations, PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx> with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility

²¹ See 18 CFR §§ 35.2, 154.2, 154.208 and 341.2.

²² Federal Energy Regulatory Commission, Order No. 714, 124 FERC ¶ 61,270.

regulatory commissions in the PJM Region²³ alerting them that this filing has been made by PJM today and is available by following such link. PJM is also serving electronic copies of this filing on all persons listed on the Commission's official service list for these proceedings.

VIII. Conclusion

For the reasons discussed herein, PJM requests that the Commission accept the proposed revisions to the Tariff.

Respectfully submitted,



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²³ PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected commissions.

Attachment A

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

(Marked / Redline Format)

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

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational

requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Demand Resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) **Bilateral Transactions.**

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in

obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a

Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as “remote self-supply of Station Power”), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility’s negative net output from Market Seller’s generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members’ dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency

exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) 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 section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. 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.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or demand resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers

offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or demand resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve ~~can~~shall be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Section 2.5(d) below, all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may

arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. Resources, the entire output of which has been designated as emergency energy, and resources that aren't available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

(d) The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability

of a generation resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.

- (e) All Non-Synchronized Reserve offers shall be for \$0.00/MWh.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM

Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

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

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

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

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

3.2.2 Regulation.

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

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

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

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

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

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

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

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

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

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

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

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

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy

offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

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

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

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

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

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

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell

frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

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

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three

suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

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

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

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

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

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

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

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

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for

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

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

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

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

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a

segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

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

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where $URLTMP - UB$ shall not be negative.

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

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

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

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

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

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

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

where $URLTMP - UDALMP$ and $URLTMP - UB$ shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at

the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

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

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, *has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals*, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price

schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where $URLMP - UB$ shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

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

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

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

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

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

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
- (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.
- (i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.
- (j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.
- (k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-

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

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being

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

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

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

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

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

where:

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

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

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

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

UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.2.3A Synchronized Reserve.

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

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

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

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

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the

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

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

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

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

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the

generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled ~~by the owner~~ to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for ~~the contiguous~~ all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. ~~and the owner of~~ The resource shall ~~incur~~ refund payments received for Tier 2 Synchronized Reserve it failed to provide. The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price ~~an additional Synchronized Reserve Obligation in~~ by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Internal Market Buyers based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour. ~~three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Reserve Zone and Reserve Sub-zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.~~

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

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

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

3.2.3A.001 Non-Synchronized Reserve.

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

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour.

Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

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

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

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

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

(f) Any amounts credited for Non-Synchronized Reserve in an hour in excess of the Non-Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to

each Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

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

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

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-

Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$

where:

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where $URTLMP - UB$ shall not be negative.

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

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

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

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

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

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

where $UB - URTLMP$ shall not be negative.

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

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

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

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

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

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market

Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Demand Resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM

Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

- (i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.
- (ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.
- (iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.
- (iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.
- (v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup

used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

- (vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

- (i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller

during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), “net output” of a generation facility during any month means the facility’s gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility’s or a Market Seller’s monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

- (ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as “remote self-supply of Station Power”), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility’s negative net output from Market Seller’s generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.
- (iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such

generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This section shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) 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 section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the

procedures specified in Section II.B of Attachment M - Appendix. 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.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or demand resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or demand resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve ~~can~~shall be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for

which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Section 2.5(d) below, all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. Resources, the entire output of which has been designated as emergency energy, and resources that aren't available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for

system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

(d) The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability of a generation resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.

(e) All Non-Synchronized Reserve offers shall be for \$0.00/MWh.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, or otherwise be construed to define PJM Settlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the

Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load

Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

- (a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.
- (b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.
- (c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.
- (d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.
- (e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.
- (f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

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

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

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

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

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

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

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

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

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

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

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

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

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the

resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

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

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

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

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

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

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

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

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

- (i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).
- (ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.
- (iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the

Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

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

- (i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing

Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

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

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

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

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

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

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

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

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

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

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched

economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any

Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where $URLTLP - UB$ shall not be negative.

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

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.
- (ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) $\{(URLTLP - UDALMP) \times DAG\}$, or (ii) $\{(URLTLP - UB) \times DAG\}$ where:

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

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

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

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

which case the offer for the unit will be determined from the cost-based schedule; and

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

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

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

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, *has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is* operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to $\{(LMPD_{MW} - AG) \times (URTLMP - UB)\}$, where:

$LMPD_{MW}$ equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where $URLMP - UB$ shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

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

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer

or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

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

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

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

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
 - (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
 - (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.
- (i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for

purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

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

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

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that

the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

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

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

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

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

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

where:

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

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

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

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

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh - Day-Ahead MWh.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

3.2.3A Synchronized Reserve.

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

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

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

Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

- ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions (“Tier 2 Synchronized Reserve”) shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.
- iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

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

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

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

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

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

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

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

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

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

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled ~~by the owner~~ to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for ~~the contiguous~~ all hours the resource was assigned ~~or self-scheduled~~ Tier 2 Synchronized Reserve on the Operating Day during which the event occurred, ~~and the owner of~~ the resource shall incur refund payments received for Tier 2 Synchronized Reserve it failed to provide. The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price an additional Synchronized Reserve Obligation in by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Internal Market Buyers based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market

~~Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour, three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Reserve Zone and Reserve Sub-zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.~~

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

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region,

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

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

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

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

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are

providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order times, (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling

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

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

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

- (i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.
- (ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.
- (iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch

instruction from the Office of the Interconnection that is no longer necessary to reduce.

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

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

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity’s load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity’s Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$

where:

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where $URTLMP - UB$ shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the

Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

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

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

AG equals the actual hourly integrated output of the unit;

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

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

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

where $UB - URLMP$ shall not be negative.

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

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

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the

PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

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

the resource was dispatched in association with post-contingency operation in such transmission zone.

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

(d) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market

Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

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

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

Attachment B

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

(Clean Format)

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

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational

requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Demand Resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) **Bilateral Transactions.**

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in

obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a

Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as “remote self-supply of Station Power”), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility’s negative net output from Market Seller’s generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members’ dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency

exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) 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 section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. 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.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or demand resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers

offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or demand resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Section 2.5(d) below, all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may

arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. Resources, the entire output of which has been designated as emergency energy, and resources that aren't available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

(d) The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability

of a generation resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.

- (e) All Non-Synchronized Reserve offers shall be for \$0.00/MWh.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non- Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM

Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

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

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

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

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

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

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

3.2.2 Regulation.

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

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

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

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

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

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

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

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

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

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

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

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

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy

offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

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

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

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

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

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

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell

frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

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

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

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

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

$\delta=0 \text{ to } 5 \text{ Min}$

where δ is delay.

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three

suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

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

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

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

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

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

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

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

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for

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

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

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

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

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a

segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

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

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where $URLTMP - UB$ shall not be negative.

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

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

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

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

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

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

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

where $URLTMP - UDALMP$ and $URLTMP - UB$ shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at

the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

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

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, *has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals*, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price

schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where $URLMP - UB$ shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

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

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

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

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

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

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
- (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.
- (i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.
- (j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.
- (k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-

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

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

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

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being

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

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

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

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

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

where:

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

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

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

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

UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.2.3A Synchronized Reserve.

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

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

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

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

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the

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

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

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

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

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

(e) In determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the

generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

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

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

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

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

Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.001 Non-Synchronized Reserve.

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

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the

Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

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

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

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

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

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and

possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

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

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

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$

where:

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where $URTLMP - UB$ shall not be negative.

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

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

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

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

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

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

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

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

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

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by

PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to $\{(AG - LMPDMW) \times (UB - URTLMP)\}$ where:

AG equals the actual hourly integrated output of the unit;

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

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

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

where $UB - URTLMP$ shall not be negative.

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

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

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided

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

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

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

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

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

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

unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

Section(s) of the
PJM Operating Agreement
(Clean Format)

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and each Applicable Regional Entity, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market

Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of interruption of load, Price Responsive Demand, Demand Resources, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM

Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

- (i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.
- (ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.
- (iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.
- (iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.
- (v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup

used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

- (vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through Load Management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

- (i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller

during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), “net output” of a generation facility during any month means the facility’s gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility’s or a Market Seller’s monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

- (ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as “remote self-supply of Station Power”), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility’s negative net output from Market Seller’s generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.
- (iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such

generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Entity reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJM Settlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This section shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Entity reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) 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 section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the

procedures specified in Section II.B of Attachment M - Appendix. 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.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or demand resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or demand resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve can be supplied from non-emergency generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve to the Office of the Interconnection, as applicable to the capacity resource's capability to provide these services. During periods for

which the Office of the Interconnection has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning as described in Section 2.5(d) below, all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources located within the metered boundaries of the PJM Region. Resources, the entire output of which has been designated as emergency energy, and resources that aren't available to provide energy, are not eligible to provide Non-Synchronized Reserve. All other non-emergency generation capacity resources available to provide energy shall also be available to provide Non-Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals, the Operating Agreement and PJM Tariff.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone and Reserve Sub-zone, as specified in the PJM Manuals. The Office of the Interconnection shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for

system reliability. Such needs may arise due to planned and unplanned system events that limit the Office of the Interconnection's ability to deliver reserves to specific geographic area of the PJM Region where reserves are required.

(c) The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

(d) The Non-Synchronized Reserve capability of a generation resource shall generally be determined based on the startup and notification time, economic minimum and ramp rate of such resource submitted in the Real-time Energy Market for the Operating Day. If the Generating Market Buyer or Market Seller offering the Non-Synchronized Reserve can demonstrate to the Office of the Interconnection that the Non-Synchronized Reserve capability of a generation resource exceeds its calculated value based on market offer data, the Generating Market Buyer or Market Seller and the Office of the Interconnection may agree on a different capability to be used.

(e) All Non-Synchronized Reserve offers shall be for \$0.00/MWh.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, Non-Synchronized Reserve market and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, or otherwise be construed to define PJM Settlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, Non-Synchronized Reserve or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the

Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load

Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for automation and supervisory control equipment that satisfy the criteria set forth in the RAA to ensure automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

- (a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.
- (b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.
- (c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.
- (d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.
- (e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.
- (f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

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

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

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

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

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

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

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

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

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

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

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

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

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the

resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

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

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

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

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

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

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

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

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

- (i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).
- (ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.
- (iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the

Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

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

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

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

- (i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing

Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

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

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

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

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

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

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

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

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

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

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched

economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

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

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

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any

Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where $URLTLP - UB$ shall not be negative.

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

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.
- (ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) $\{(URLTLP - UDALMP) \times DAG\}$, or (ii) $\{(URLTLP - UB) \times DAG\}$ where:

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

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

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

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

which case the offer for the unit will be determined from the cost-based schedule; and

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

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

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

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled, *has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is* operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to $\{(LMPD_{MW} - AG) \times (URTLMP - UB)\}$, where:

$LMPD_{MW}$ equals the lesser of the PJM forecasted output for the unit or level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where $URLMP - UB$ shall not be negative.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

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

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

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer

or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

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

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

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

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
 - (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
 - (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.
- (i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for

purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

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

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

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

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than \$1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that

the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

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

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

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

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

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

where:

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

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

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

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

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – UDS LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the hour is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – UDS LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real-time MWh - Day-Ahead MWh.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

3.2.3A Synchronized Reserve.

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

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

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

Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

- ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions (“Tier 2 Synchronized Reserve”) shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.
- iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

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

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

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

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

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

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

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

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

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

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all hours the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Internal Market Buyers based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the

Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

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

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

3.2.3A.001 Non-Synchronized Reserve.

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

the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

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

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

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

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

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

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

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

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM

Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

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

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

- (i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.
- (ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.
- (iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.
- (iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as

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

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

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

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

3.2.3B Reactive Services.

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

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

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller

for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$

where:

LMP_{DMW} equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

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

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where $URTLMP - UB$ shall not be negative.

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

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

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

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

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

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

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

where $URLTMP - UDALMP$ and $URLTMP - UB$ shall not be negative.

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

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

AG equals the actual hourly integrated output of the unit;

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

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

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

where $UB - URLTMP$ shall not be negative.

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

Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

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

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

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

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

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in

the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

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

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

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

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing

statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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