PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403-2497

Daniel Vinnik
Counsel
T: (267)-858-9451
Daniel.Vinnik@pjm.com

January 22, 2025

The Honorable Debbie-Anne A. Reese
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426-0001

Re: *PJM Interconnection, L.L.C., Docket No. ER25-1022-000*
Governing Document Enhancements and Clarifications of the Tariff, Operating Agreement, and Reliability Assurance Agreement

Dear Secretary Reese:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the Federal Energy Regulatory Commission's ("Commission") Regulations,[2] PJM Interconnection, L.L.C. ("PJM") hereby submits for filing clerical and ministerial revisions to correct, clarify, and/or make consistent certain provisions of the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"). PJM respectfully requests that the Commission accept the enclosed revisions with an effective date of March 24, 2025.

I. BACKGROUND

In the last several years, PJM has used its Governing Documents Enhancement and Clarification Subcommittee ("GDECS") stakeholder process as the primary vehicle to effectuate review of its Governing Documents to ensure that provisions are clear, consistent, and accurately reflect PJM's practices and procedures. To date, PJM has submitted several filings to correct and

---

[1] 16 U.S.C. § 824d (2020).

[2] 18 C.F.R. Part 35 (2020).

clarify definitions and provisions identified via GDECS that were ambiguous, incorrect, or required additional detail, which the Commission has accepted.[3]

In establishing GDECS, PJM and its stakeholders intended to utilize the GDECS process as a means to continually review and make non-controversial substantive and non-substantive revisions to the Governing Documents.[4] Through these ongoing efforts, PJM has identified a number of additional revisions that will help clarify, correct, and/or reflect previously filed and accepted revisions to PJM's Governing Documents, thereby decreasing the likelihood of compliance violations through misinterpretation or ambiguity in the language of a given provision. Other proposed revisions will correct or remove language that does not accurately describe the current processes that PJM utilizes or is no longer applicable, in an effort to eliminate inconsistencies between provisions within the Governing Documents or otherwise bring the Governing Documents up to date.

II. PROPOSED REVISIONS

The revisions proposed herein remove obsolete provisions and terms, eliminate ambiguity, modify incorrect references, correct formatting errors, and otherwise clarify provisions. For ease of review of the proposed revisions, PJM has provided a table appended hereto as Attachment C, which describes the proposed revisions, the Governing Document in which the revision is being

---

[3] *See, e.g., PJM Interconnection L.L.C.*, Delegated Letter Order, Docket No. ER19-744-000 (Feb. 4, 2019); *PJM Interconnection L.L.C.*, Delegated Letter Order, Docket No. ER18-1528-000 (June 25, 2018); *PJM Interconnection, L.L.C.*, Delegated Letter Order, Docket No. ER17-1372-000 (May 17, 2017); *PJM Interconnection, L.L.C.*, Delegated Letter Order, Docket No. ER16-1737-000 (June 20, 2016); *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,303 (2016) (accepting all proposed revisions except one); and *PJM Interconnection L.L.C.*, Delegated Letter Order, Docket No. ER19-2799-000 (Oct. 9, 2020).

[4] *See* PJM, GDECS Charter, at https://www.pjm.com/-/media/committees-groups/subcommittees/gdecs/20151023/20151023-charter.ashx?la=en (indicating that meetings will be held as needed and that expected duration of the work of the subcommittee to be "indefinite").

made, the current language, and the rationale for making the referenced changes. Given that each of the proposed revisions are discrete, severable, and not interdependent, PJM requests that the Commission evaluate the justness and reasonableness of these revisions separately.[5]

III. STAKEHOLDER PROCESS

PJM brought these proposed corrections to the attention of stakeholders through the Governing Documents Enhancements and Clarifications Subcommittee ("GDECS") on August 28, 2024. The GDECS approved the corrections by acclamation on September 30, 2024.[6] The corrections were then presented before the Markets and Reliability Committee ("MRC") and approved as part of the consent agenda on November 21, 2024, by acclamation with no objections or abstentions.[7] The corrections were approved as part of the consent agenda by the Members Committee on December 18, 2024, by acclamation with no objections or abstentions.[8] Because the corrections contain sections of the RAA, the PJM Board of Managers also authorized this filing during the November 2024 PJM Board of Managers meeting.[9] The specific circumstances relevant

---

[5] *See NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114-15 (D.C. Cir. 2017) (finding that the Commission has "authority to propose modifications to a utility's [FPA section 205] proposal if the utility consents to the modifications") (emphasis in original); *see also Public Service Company of New Mexico*, 178 FERC ¶ 61,088, at P 31 n.48 (2022) (accepting the filer's proposed tariff revisions, but directing certain revisions to remove specific charges, as agreed to by the filer) (citing 862 F.3d 108); *Southwest Power Pool, Inc.*, 177 FERC ¶ 61,148, at P 27 n.42 (2021); *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,080, at P 43 n.54 (2021); *Southwest Power Pool, Inc.*, 177 FERC ¶ 61,230, at P 24 n.43 (2021).

[6] The timeline for this GDECS item was posted for the September 30, 2024 GDECS meeting and is available here: https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/gdecs/2024/20240930/20240930-item-04----gdecs-timeline.pdf.

[7] The Consent Agenda for the November 21, 2024 MRC meeting is available here: https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241218/20241218-consent-agenda-a---draft-mrc-minutes---11212024.pdf.

[8] The GDECS Presentation for the December 18, 2024 MC Consent Agenda C is available here: https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2024/20241218/20241218-consent-agenda-c---1-gdecs-governing-document-revisions---presentation.pdf.

[9] RAA, Article 16.4 provides that the RAA may be amended only by action of the Board, and that PJM shall file with the Commission any amendment to the RAA approved by the Board.

to each provision containing such inadvertent capitalizations are described in detail in Attachment C to this filing.

IV. PROPOSED EFFECTIVE DATE

PJM respectively requests that the Commission accept the enclosed revisions to the PJM Tariff, Operating Agreement, and RAA, effective March 24, 2025.

V. DESCRIPTION OF SUBMITTAL

This filing consists of the following:

1. This transmittal letter;

2. Attachment A – Revisions to the Tariff, Operating Agreement, and RAA in redline format;

3. Attachment B – Revisions to the Tariff, Operating Agreement, and RAA in clean format;[10] and

4. Attachment C – Chart of revisions.[11]

---

[10] The portions of Attachment A and B of this filing that contain revisions to Tariff, Schedule 6A reflect revisions to the most recently accepted and effective language, as reconciled in PJM's ministerial clean-up filing on Friday January 17, 2025, in Docket No. ER25-967-000. *See PJM Interconnection, L.L.C.*, Administrative Clean-Up Filing, Docket No. ER25-967-000 (January 17, 2025). Although the Commission has not yet accepted that filing, the language contained therein was all previously accepted by the Commission and has been included herein to avoid overlapping accepted tariff sheets with outdated language that would require a subsequent clean-up filing. To the extent the Commission deems necessary, PJM renews its proposal to update the aforementioned section as part of this filing and incorporates those changes herein.

[11] The information in the Governing Document column of Row 35 of Attachment C has been corrected to reference Tariff, Attachment DD, section 5.6.1(g) instead of section 5.8(g) which inadvertently appeared on the chart considered at stakeholder meetings and available on PJM's website at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241121/20241121-consent-agenda-h---2-gdecs-revisions-chart---redlines.pdf. The redline language considered remains unchanged.

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:

Daniel Vinnik
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, Pennsylvania 19403
(267) 858-9451
daniel.vinnik@pjm.com

Craig Glazer
Vice President - Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W, Suite 600
Washington, D.C. 20005
(202) 423-4743
craig.glazer@pjm.com

VII. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[12] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[13] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

---

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

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

VIII. CONCLUSION

Based on the foregoing, PJM respectfully requests that the Commission accept the proposed revisions to PJM's governing documents to be effective March 24, 2025.

Respectfully submitted,

/s/ Daniel Vinnik

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743 (phone)
(202) 393-7741 (fax)
Craig.Glazer@pjm.com

Daniel Vinnik
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA* 19403
(*Barred in the District
of Columbia and Illinois)
(267) 858-9451 (phone)
Daniel.Vinnik@pjm.com

Attachment A

Revisions to the
PJM Open Access Transmission Tariff,
PJM Operating Agreement
and PJM Reliability Assurance Agreement

(Marked / Redline Format)

Definitions – A - B

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

"Abnormal Condition" shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Affected System:

"Affected System" shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

"Affected System Operator" shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

"Agreements" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:

"Ancillary Services" shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

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

Annual Energy Efficiency Resource:

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

Annual Resource:

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

Annual Revenue Rate:

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

Annual Transmission Costs:

"Annual Transmission Costs" shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

"Applicable Laws and Regulations" shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

"Applicable Technical Requirements and Standards" shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, "Applicable Technical Requirements and Standards" shall refer to the "PJM Small Generator Interconnection Applicable Technical Requirements and Standards." All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider's internet website.

Applicant:

"Applicant" shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

"Application" shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

"Attachment Facilities" shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

"Attachment H" shall refer collectively to the Attachments to the PJM Tariff with the prefix "H" that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

"Authorized Government Agency" means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

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

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

"Balancing Ratio" shall have the meaning provided in Tariff, Attachment DD, section 10A.

~~**Base Capacity Demand Resource:**~~

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

~~**Base Capacity Demand Resource Constraint:**~~

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

~~For both the PJM Region and LDA analyses, PJM then models the commitment of varying~~

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

~~Base Capacity Energy Efficiency Resource:~~

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

~~Base Capacity Resource:~~

~~"Base Capacity Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).~~

~~Base Capacity Resource Constraint:~~

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

~~For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].~~

Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Economic Load Response Participant Resource:

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

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

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

Buy Bid:

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

Buyer-Side Market Power:

"Buyer-Side Market Power" shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – C - D

Canadian Guaranty:

“Canadian Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

“Cancellation Costs” shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

“Capacity” shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

“Capacity Emergency Transfer Limit” or “CETL” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:

“Capacity Emergency Transfer Objective” or “CETO” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Export Transmission Customer:

“Capacity Export Transmission Customer” shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

“Capacity Import Limit” shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

"Capacity Interconnection Rights" shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:

"Capacity Performance Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

~~**Capacity Performance Transition Incremental Auction:**~~

~~"Capacity Performance Transition Incremental Auction" shall have the meaning specified in Tariff, Attachment DD, section 5.14D.~~

Capacity Resource:

"Capacity Resource" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

"Capacity Resource with State Subsidy" shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

Capacity Resource Clearing Price:

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

Capacity Transmission Injection Rights:

"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Charge Mode. Charge Economic

Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Charge Mode.

Cleared Capacity Resource with State Subsidy:

"Cleared Capacity Resource with State Subsidy" shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Closed-Loop Hybrid Resource:

"Closed-Loop Hybrid Resource" shall mean a Hybrid Resource that is physically or contractually incapable of charging from the grid.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

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

Collateral:

"Collateral" shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. "Collateral" shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

"Collateral Call" shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Co-Located Resource:

"Co-Located Resource" shall mean a component of a Mixed Technology Facility that operates in the capacity, energy, and/or ancillary services market(s) as a separate resource from the other components of such facility.

Commencement Date:

"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The "Committed Offer" shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

“Completed Application” shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Composite Energy Offer:

“Composite Energy Offer” for generation resources shall mean the sum (in $/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in $/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

Conditional Incremental Auction:

“Conditional Incremental Auction” shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

Conditioned State Support:

“Conditioned State Support” shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where “conditioned on clearing in any RPM Auction” refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

"CONE Area" shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

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

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

"Construction Service Agreement" shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

"Contingent Facilities" shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

"Continuous Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants or solar-storage Open-Loop Hybrid Resource operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

"Control Zone" shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

"Controllable A.C. Merchant Transmission Facilities" shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

"Corporate Guaranty" shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

Cost of New Entry:

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, "Costs" shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

Credit Affiliate:

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

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

Credit Available for Virtual Transactions:

"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

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

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

Critical Natural Gas Infrastructure:

"Critical Natural Gas Infrastructure" shall mean locations with electrical loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility as defined by NERC/FERC standard(s); and until such NERC/FERC standard(s) is developed, is defined as electric loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility, which if curtailed, will impact the delivery of natural gas to bulk-power system natural gas-fired generation.

Cross-Border:

When used to describe Network Integration Transmission Service, Network External Designated Transmission Service or Point-to-Point Transmission Service, "Cross-Border" shall mean transmission service where the capacity and/or energy is delivered from a resource that is not part of the PJM Transmission System and/or to load that is not part of the PJM Transmission System.

CTS Enabled Interface:

"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

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

Customer Facility:

"Customer Facility" shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

"Customer-Funded Upgrade" shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

"Customer Interconnection Facilities" shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13.

Daily Unforced Capacity Obligation:

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

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

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

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

Day-ahead Prices:

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

Day-Ahead Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

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

Deactivation:

“Deactivation” shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

“Deactivation Avoidable Cost Credit” shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

“Deactivation Avoidable Cost Rate” shall mean the formula rate established pursuant to Tariff, Part V, section 115.

Deactivation Date:

“Deactivation Date” shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

“Decrement Bid” shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, “Default” shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

“Delivering Party” shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

“Delivery Year” shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

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

Demand Bid Limit:

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

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

~~**Demand Resource:**~~

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

~~**Demand Resource Factor or DR Factor:**~~

~~"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.~~

Designated Agent:

"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the

Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource or Open-Loop Hybrid Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource is only injecting megawatts onto the grid).

Discharge Ramp Rate:

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Discharge Mode.

Dispatch Rate:

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

Dispatched Charging Energy:

“Dispatched Charging Energy” shall mean Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants and Open-Loop Hybrid Resource shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

“Dynamic Schedule” shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

“Dynamic Transfer” shall have the same meaning provided in the Operating Agreement.

Definitions – E - F

Economic-based Enhancement or Expansion:

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

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

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

Economic Minimum:

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

Effective FTR Holder:

“Effective FTR Holder” shall mean:

(i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:

"Electrical Distance" shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

"Eligible Customer" shall mean:

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

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

Eligible Fast-Start Resource:

"Eligible Fast-Start Resource" shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency Action:

"Emergency Action" shall mean (1) any megawatt shortage of the Primary Reserve Requirement (as specified in the PJM Manuals) in a Reserve Zone or Reserve Sub-zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of non-essential building loads and Voltage Reduction Warning that encompasses such Reserve Zone or Reserve Sub-zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for an entire Reserve Zone or Reserve Sub-zone.

Emergency Condition:

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

Emergency Load Response Program:

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

Energy Efficiency Resource:

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

Energy Market Opportunity Cost:

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

Energy Resource:

"Energy Resource" shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

"Energy Settlement Area" shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

"Energy Storage Resource Model Participant" shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

"Energy Storage Resource Participation Model" shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

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

Entity Providing Supply Services to Default Retail Service Provider:

"Entity Providing Supply Services to Default Retail Service Provider" shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

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

Event of Default:

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Exercise of Buyer-Side Market Power:

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

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

Export Credit Exposure:

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

Export Nodal Reference Price:

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

Export Transaction:

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

Export Transaction Price Factor:

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

Export Transaction Screening:

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

Export Transactions Net Activity:

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

~~Extended Summer Demand Resource:~~

~~“Extended Summer Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.~~

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

“Extended 30-minute Reserve Requirement” shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

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

External Resource:

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

Facilities Study:

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

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

Financial Default:

"Financial Default" shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall mean Transmission Service under the Tariff, Part II, section 13 that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

"Firm Transmission Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

“Forecast Pool Requirement” shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

"Forward Hourly LMPs" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

"FTR Credit Limit" shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

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

FTR Flow Undiversified:

"FTR Flow Undiversified" shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, "FTR Historical Value" shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

"FTR Holder" shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

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

FTR Net Activity:

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

FTR Participant:

"FTR Participant" shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM's FTR market.

FTR Portfolio Auction Value:

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

Fuel Cost Policy:

"Fuel Cost Policy" shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller's method used to price fuel for calculation of the Market Seller's cost-based offers for a generation resource.

Full Notice to Proceed:

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

Definitions – L – M – N

Legacy Policy:

"Legacy Policy" shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

~~**Limited Demand Resource:**~~

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

~~**Limited Demand Resource Reliability Target:**~~

~~"Limited Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will~~

~~not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].~~

~~Limited Resource Constraint:~~

~~"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.~~

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

"Load Interest" shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

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

Load Management Event:

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

Load Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:

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

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

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

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind or solar units, Hybrid Resources, or Energy Storage Resources, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind or solar units, Hybrid Resources, or Energy Storage Resources, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output, inclusive of state of charge, for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area. Notwithstanding the foregoing, for the 2024/2025 Delivery Year, during the auction process, the Office of Interconnection shall exclude from the Locational Deliverability Area Reliability Requirement any Planned Generation Capacity Resource in an LDA that does not participate in the relevant RPM Auction as projected internal capacity and in the Capacity Emergency Transfer Objective model where the Locational Deliverability Area Reliability Requirement for the Base Residual Auction increases by more than one percent over the reliability requirement used from the prior Delivery Year's Base Residual Auction (for Incremental Auctions the Locational Deliverability Area Reliability Requirement would be compared with the reliability requirement used in the prior relevant RPM Auction associated with the same Delivery Year) for that LDA due to the cumulative addition of such Planned Generation Capacity Resources.

Locational Price Adder:

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

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

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

"Marginal Value" shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

"Market Monitor" means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

"Market Monitoring Unit Advisory Committee" or "MMU Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

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

Market Participant:

"Market Participant" shall mean a Market Buyer, a Market Seller, and/or an Economic Load Response Participant, or all three, except when that term is used in or pertaining to Tariff, Attachment M, Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4. "Market Participant," when such term is used in Tariff, Attachment M, shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale. "Market Participant," when such term is used in or pertaining to Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4, shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, an FTR Participant, a Capacity Market Buyer, or a Capacity Market Seller.

Market Participant Energy Injection:

"Market Participant Energy Injection" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

"Market Participant Energy Withdrawal" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

"Market Revenue Neutrality Offset" shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Suspension:

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

Market Violation:

"Market Violation" shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

"Material Modification" shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

"Maximum Daily Starts" shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

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

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

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

Maximum Generation Emergency Alert:

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

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

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

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

~~**Minimum Annual Resource Requirement:**~~

~~"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource~~

~~Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.~~

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Exposure:

"Minimum Exposure" shall mean the greater of: (a) $3,000 and (b) one percent (1%) of the greatest amount invoiced for the Participant's transaction activity for all PJM Markets and services in any rolling one, two, or three-week period in the prior 52 weeks, rounded up to the nearest multiple of $100; provided, however, that the Minimum Exposure shall be capped at a maximum of $100,000.

~~**Minimum Extended Summer Resource Requirement:**~~

~~"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.~~

Minimum Generation Emergency:

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

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero to the time of the last generator breaker opening as measured by PJM's State Estimator.

Minimum Transfer Amount:

"Minimum Transfer Amount" shall mean the greater of: (a) $20,000 and (b) five percent (5%) of the greatest amount invoiced for the Participant's transaction activity for all PJM Markets and services in any rolling one, two, or three-week period in the prior 52 weeks, rounded up to the nearest multiple of $100; provided, however, that the Minimum Transfer Amount shall be capped at a maximum of $500,000.

MISO:

"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

"Mixed Technology Facility" shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

"MOPR Floor Offer Price" shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, section~~s 5.14(h), 5.14(h-1), and~~ 5.14(h-2).

Multi-Driver Project:

"Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

"Native Load Customers" shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner's system to meet the reliable electric needs of such customers.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

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

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

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

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III. There are two types of firm Network Integration Transmission Service: Regional Network Integration Transmission Service and firm Cross-Border Network Integration Transmission Service. Non-firm Network Integration Transmission Service includes Secondary Service.

Network Load:

"Network Load" shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer's Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

"Network Operating Agreement" shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

"Network Operating Committee" shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

"Network Resource" shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

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

Network Transmission Service:

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

Network Upgrades:

"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

"Neutral Party" shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

"New Entry Capacity Resource with State Subsidy" shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

"New Services Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

"Non-Performance Charge" shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

"Nonincumbent Developer" shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

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

Non-Retail Behind The Meter Generation:

"Non-Retail Behind The Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

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

Non-Synchronized Reserve Event:

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

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

"Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

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

Normal Minimum Generation:

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

Definitions – O – P - Q

Obligation:

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

Offer Data:

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

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

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

On-Site Generators:

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

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-Time Information System" or "OASIS" shall mean the electronic communication and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Open-Loop Hybrid Resource:

"Open-Loop Hybrid Resource" shall mean a Hybrid Resource with a storage component that is physically and contractually capable of charging its storage component from the grid.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

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

Operating Margin:

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

Operating Margin Customer:

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

Operating Reserve Demand Curve:

"Operating Reserve Demand Curve" shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement.

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy from the external Generation Capacity Resource to loads in the PJM Region in a manner comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

OPSI Advisory Committee:

"OPSI Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

"Option to Build" shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

"Optional Interconnection Study" shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

"Optional Interconnection Study Agreement" shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

"Part I" shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

"Part II" shall mean Tariff, Part II, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

"Part III" shall mean Tariff, Part III, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

"Part IV" shall mean Tariff, Part IV, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

"Part V" shall mean Tariff, Part V, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

"Part VI" shall mean Tariff, Part VI, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

"Participant" shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer**.**

Parties:

"Parties" shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle), plus 10% of such costs only for the 2022/2023 Delivery Year, for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate, plus 10% of such costs only for the 2022/2023 Delivery Year, under the same conditions as described above for the Day-ahead Energy Market.

Peak Market Activity:

"Peak Market Activity" shall mean a measure of exposure for which credit is required, calculated in accordance with Tariff, Attachment Q, section VII.A.

Peak Market Activity Shortfall:

"Peak Market Activity Shortfall" shall mean, for any given week, the amount by which a Participant's current Peak Market Activity exceeds such Participant's Peak Market Activity credit requirement from the prior week.

Peak Market Activity Surplus:

"Peak Market Activity Surplus" shall mean, for any given week, the amount by which a Participant's Peak Market Activity credit requirement from the prior week exceeds such Participant's current Peak Market Activity.

Peak Season:

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

Performance Assessment Interval:

"Performance Assessment Interval" shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection~~, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September~~.

Permissible Technological Advancement:

"Permissible Technological Advancement" shall mean a proposed technological change such as an advancement to turbines, inverters, plant supervisory controls or other similar advancements to the technology proposed in the Interconnection Request that is submitted to the Transmission Provider no later than the return of an executed Facilities Study Agreement (or, if a Facilities Study is not required, prior to the return of an executed Interconnection Service Agreement). Provided such change may not: (i) increase the capability of the Generating Facility as specified in the original Interconnection Request; (ii) represent a different fuel type from the original Interconnection Request; or (iii) cause any material adverse impact(s) on the Transmission System with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response. If the proposed technological advancement is a Permissible Technological Advancement, no additional study will be necessary and the proposed technological advancement will not be considered a Material Modification.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

"PJM Administrative Service" shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

"PJM Control Area" shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

"PJM Entities" shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM's officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

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

PJM Interchange Energy Market:

"PJM Interchange Energy Market" shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

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

PJM Interchange Import:

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

PJM Liaison:

"PJM Liaison" shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

"PJM Management" shall mean the officers, executives, supervisors and employee managers of PJM.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Markets:

"PJM Markets" shall mean the PJM Interchange Energy Market, capacity markets, including the RPM auctions, and any other market operated by PJM, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions, Financial Transmission Rights transactions, or transactions in any other market operated under the Agreements within the PJM Region, wherein Market Participants may incur Obligations to PJM and/or PJMSettlement.

PJM Market Rules:

"PJM Market Rules" shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

"PJM Net Assets**"** shall mean the total assets per PJM's consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

"PJM Region" shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:
"PJM Regional Practices Document" shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

"PJM Region Installed Reserve Margin" shall mean the percent installed reserve margin for the PJM Region required pursuant to RAA, Schedule 4.1, as approved by the PJM Board.

PJM Region Peak Load Forecast:

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in Tariff, Attachment DD, section 5.

PJM Region Reliability Requirement:

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

PJMSettlement:

"PJM Settlement" or "PJM Settlement, Inc." shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operaitng Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T.," "OATT," or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

"Plan" shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

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

Planned External Generation Capacity Resource:

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Planned Generation Capacity Resource:

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

Planning Period:

"Planning Period" shall mean the 12 moths beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Planning Period Balance:

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

Planning Period Quarter:

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

Point(s) of Delivery:

"Point(s) of Delivery" shall mean the point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

"Point of Interconnection" shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

"Point(s) of Receipt" shall mean point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

"Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

"Power Purchaser" shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

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

PRD Provider:

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

PRD Reservation Price:

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

PRD Substation:

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

Pre-Confirmed Application:

"Pre-Confirmed Application" shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

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

Pre-Expansion PJM Zones:

"Pre-Expansion PJM Zones" shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC ("MAIT") (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

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

Primary Reserve:

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

Primary Reserve Alert

"Primary Reserve Alert" shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

"Primary Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Principal:

"Principal" shall mean (i) all natural persons who Control Corporate Level Strategy for the Participant, which shall include a chief executive officer, managing member (or equivalent positions regardless of title) and members of a board of directors or board of managers; (ii) the chief legal officer or general counsel (or equivalent position regardless of title); (iii) the natural person who Controls the financial affairs and investments of the Participant, which shall include a chief financial officer (or equivalent position regardless of title); (iv) the natural person who Controls the Participant's management of commodity and derivatives market risks, which shall include a chief risk officer (or equivalent position regardless of title); (v) the natural person who Controls the Participant's transactions in the applicable PJM Markets (regardless of title); and (vi) all Beneficial Owners.

"Control," as that term is used in this definition, refers to possession of the power to direct the management or policies of an entity.

"Corporate Level Strategy," as that term is used in this definition, refers to the highest-level strategy of an entity, focused on the entity's overall direction rather than the day-to-day operations of the entity.

"Beneficial Owner," as that term is used in this definition, means a natural person who, directly or indirectly, alone or together with such person's Family Members, owns, controls, or holds with power to vote 10 percent or more of the outstanding securities of the Participant.

"Family Member," as that term is used in this definition of "Beneficial Owner," means a spouse, domestic partner, parent, child, or sibling.

For purposes of trusts with, directly or indirectly, 10 percent or more of the outstanding securities of the Participant as described above, the following are Beneficial Owners: (a) a natural person trustee; (b) a natural person with the authority to dispose of the trust assets; (c) a natural person grantor or settlor who has the right to revoke the trust or otherwise withdraw the assets of the trust; and (d) a natural person beneficiary who is the sole permissible recipient of income and principal from the trust or has the right to demand a distribution of or withdraw substantially all of the assets from the trust.

If, due to the Participant's business enterprise, structure or otherwise, a function described in clauses (i) through (v) above is performed by a natural person or entity separate from the Participant (such as a risk management department in an affiliate, or a director or manager at an entity that controls or invests in the Participant), then for that Participant the term Principal shall mean that natural person, or the senior officer or manager of that entity, that performs such function.

Prior CIL Exception External Resource:

"Prior CIL Exception External Resource" shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

"Project Financing" shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

"Project Finance Entity" shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

Projected EAS Dispatch:

"Projected EAS Dispatch" shall mean, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource's offer and operating parameters. For combustion turbine units only, the cost-based energy offer will include a 10 percent adder only for the 2022/2023 Delivery Year.

Projected PJM Market Revenues:

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Proportional Multi-Driver Project:

"Proportional Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Provisional Interconnection Service:

"Provisional Interconnection Service" shall mean interconnection service provided by Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interconnection Service Agreement and, if applicable, the Tariff.

Pseudo-Tie:

“Pseudo-Tie” shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

“Public Policy Objectives” shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

“Public Policy Requirements” shall have the same meaning provided in the Operating Agreement.

Qualifying Transmission Upgrade:

“Qualifying Transmission Upgrade” shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

Queue Position:

“Queue Position” shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

Definitions – R - S

Ramping Capability:

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

Rating Agency:

"Rating Agency" shall mean a Nationally Recognized Statistical Rating Organization that assesses the financial condition, strength and stability of companies and governmental entities and their ability to timely make principal and interest payments on their debts and the likelihood of default, and assigns a rating that reflects its assessment of the ability of the company or governmental entity to make the debt payments.

Real-time Congestion Price:

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

Real-time Loss Price:

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

Real-time Energy Market:

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

Real-time Offer:

"Real-time Offer" shall mean a new offer or an update to a Market Seller's existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

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

Real-time Settlement Interval:

"Real-time Settlement Interval" shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

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

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Tariff, Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

For Delivery Years up to and including the 2025/2026 Delivery Year, "Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh. For the 2026/2027 Delivery Year and subsequent Delivery Years, "Reference Resource" shall mean a combined cycle generating station, configured with a double train 1x1 single shaft General Electric Frame 7HA.02 turbine with an F-A650 steam turbine with evaporative cooling, Selective Catalytic Reduction technology and carbon monoxide catalyst, with firm gas transportation, and a heat rate of 6.604 MMbtu/MWh (with duct firing) and 6.369 MMbtu/MWh (without duct firing).

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Network Integration Transmission Service:

"Regional Network Integration Transmission Service" shall mean firm transmission service taken by Network Customers that involves the delivery of energy and/or capacity from Network

Resources physically interconnected to the Transmission Provider's transmission system to Network Load physically interconnected to the Transmission Provider's transmission system.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

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

Regulation Zone:

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction~~, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction~~.

Required Transmission Enhancements:

"Regional Transmission Enhancements" shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:

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

Reserve Sub-zone:

"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

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

Residual Metered Load:

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

Resource Substitution Charge:

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

Restricted Collateral:

"Restricted Collateral" shall mean Collateral, held by PJM or PJMSettlement, which cannot be used, netted, credited or spent by the Participant to satisfy any other obligations.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section VI.

Scheduled Incremental Auctions:

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

Schedule of Work:

“Schedule of Work” shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider’s scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

“Scope of Work” shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider’s scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

“Seasonal Capacity Performance Resource” shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Reserve:

“Secondary Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes (less the capability of such resources to provide Primary Reserve), from the request of the Office of the Interconnection, regardless of whether the equipment providing the reserve is electrically synchronized to the Transmission System or not.

Secondary Systems:

“Secondary Systems” shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

“Second Incremental Auction” shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

Security:

“Security” shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer’s responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:

"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Self-Supply:

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "vertically integrated utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "public power entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

"Self-Supply Seller" shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where "vertically integrated utility" means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and "public power entity" means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

"Short-term Project" shall have the same meaning provided in the Operating Agreement.

~~**Short-Term Resource Procurement Target:**~~

~~"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.~~

~~**Short-Term Resource Procurement Target Applicable Share:**~~

~~"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and,~~

~~as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.~~

Site:

"Site" shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

"Small Commercial Customer," as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

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

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start Fuel:

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours)

Start-Up Costs:

"Start-Up Costs" shall consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units):

Start-Up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.

For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-Up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

"State Commission**"** shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in a storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or a storage component of a Hybrid Resource using minimum and maximum discharge (and, as applicable, charge) limits, changes in operating mode (as applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

State Subsidy:

"State Subsidy" shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

Station Power:

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

~~**Sub-Annual Resource Constraint:**~~

~~"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.~~

~~**Sub-Annual Resource Reliability Target:**~~

~~"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a~~

~~range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.~~

~~For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].~~

Sub-meter:

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

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

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

Synchronized Reserve Event:

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

Synchronized Reserve Requirement:

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

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

Definitions – T – U - V

Tangible Net Worth:

"Tangible Net Worth" shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

Third-Party Sale:

"Third-Party Sale" shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

"Tie Line" shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the

Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

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

Total Net Sell Position:

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

Total Operating Reserve Offer:

"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Trade Reference:

"Trade Reference" shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

"Transmission Constraint Penalty Factor" shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

"Transmission Customer" shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

"Transmission Facilities" shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

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

Transmission Injection Rights:

"Transmission Injection Rights" shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

"Transmission Interconnection Customer" shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

"Transmission Interconnection Facilities Study" shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

"Transmission Interconnection Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

"Transmission Interconnection Request" shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

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

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

"Transmission Owner Attachment Facilities" shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner's side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

"Transmission Owner Interconnection Facilities" shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner's side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

"Unsecured Credit" shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

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

Updated VRR Curve:

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction~~, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction~~.

Updated VRR Curve Decrement:

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with ~~the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and~~ Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with ~~the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E and~~ Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

"Upgrade Construction Service Agreement" shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

"Upgrade Customer" shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

"Upgrade Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

"Upgrade-Related Rights" shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

"Upgrade Request" shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

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

Up-to Congestion Historical Month:

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

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an "Up-to Congestion Prevailing Flow Transaction" if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

"Up-to Congestion Reference Price" for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

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

Up-to Congestion Transaction:

"Up-to Congestion Transaction" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

"Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Variable Resource Requirement Curve:

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

"Virtual Credit Exposure" shall mean the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

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

Virtual Transaction Screening:

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

Virtual Transactions Net Activity:

"Virtual Transactions Net Activity" shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

"Voltage Reduction Action" shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

"Voltage Reduction Alert" shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

"Voltage Reduction Warning" shall mean a notification from PJM to warn Members that PJM's available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

SCHEDULE 6A
Black Start Service

References to section numbers in this Schedule 6A refer to sections of this Schedule 6A, unless otherwise specified.

To ensure the reliable restoration following a shut down of the PJM transmission system, Black Start Service is necessary to facilitate the goal of complete system restoration. Black Start Service enables the Transmission Provider to designate specific generators called Black Start Units whose location and capabilities are required to re-energize the transmission system following a system-wide blackout. The Transmission Provider shall administer the provision of Black Start Service. PJMSettlement shall be the Counterparty to the purchases and sales of Black Start Service.

TRANSMISSION CUSTOMERS

1. All Transmission Customers and Network Customers must obtain Black Start Service through the Transmission Provider, with PJMSettlement as the Counterparty, pursuant to this Schedule 6A.

PROVISION OF BLACK START SERVICE

2. A Black Start Unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in the PJM manuals. The expected life of the Black Start Unit shall take into consideration expectations regarding both the enabling equipment and the generation unit itself.

A Fuel Assured Black Start Unit is a Black Start Unit that is capable of starting without an outside electrical supply and running 16 hours or more at full load and either stores at least 16 hours of fuel on site, can operate independently on 2 or more interstate pipelines, is directly connected to a natural gas gathering system or is an intermittent or hybrid resource that has been evaluated by the Transmission Provider to be capable of providing no less than 16 hours of operation per day, which need not be continuous, at a megawatt level that provides a confidence level of 90% based on an evaluation of the unit's historical operation over a representative period of time, and meets any other requirements specified in the PJM manuals. Distributed energy resources interconnected to distribution facilities may qualify as Fuel Assured Black Start Units under the criteria that applies to all Fuel Assured Black Start Units. Unless otherwise specified as only applicable to Fuel Assured Black Start Units, all terms and conditions set forth in this Tariff, Schedule 6A applicable to Black Start Units shall be deemed to include Fuel Assured Black Start Units.

3. A Black Start Plant is a generating plant that includes one or more Black Start Units. A generating plant with Black Start Units electrically separated at different voltage levels will be considered multiple Black Start Plants.

4.	The Transmission Provider is responsible for developing a coordinated and efficient system restoration plan that identifies all of the locations where Black Start Units are needed. The PJM Manuals shall set forth the criteria and process for selecting or identifying the Black Start Units necessary to commit to providing Black Start Service at the identified locations. No Black Start Unit shall be eligible to recover the costs of providing Black Start Service in the PJM Region unless it agrees to provide such service for a term of commitment established under section 5, 6, or 6A below.

5.	Owners of Black Start Units selected to provide Black Start Service in accordance with Schedule 6A, section 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner or the Transmission Provider provides written, one-year advance notice of its intention to terminate the commitment or the commitment is involuntarily terminated pursuant to section 15 of this Schedule 6A. Black Start Units that are selected to provide Black Start Service after June 6, 2021, pursuant to Schedule 6A, section 6 that subsequently transition from the Capital Cost Recovery Rate to the Base Formula Rate shall have a lifetime commitment and can only terminate for the reason specified in Schedule 6A, section 6(ii).

6.	(i) Owners of Black Start Units selected to provide Black Start Service prior to June 6, 2021, in accordance with section 4 of this Schedule 6A and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon the age of the Black Start Unit or the longest expected life of the Incremental Black Start Capital Cost, as set forth in the applicable CRF Table in section 18 of this Schedule 6A. For those Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the applicable term of commitment as set forth in the CRF Table in section 18 of this Schedule 6A. The Transmission Provider may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Black Start Unit owner shall be eligible to recover any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice and consent of the Transmission Provider (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i) of this Schedule 6A) in excess of the amount that would have been recovered pursuant to section 18 of this Schedule 6A during the same period. At the conclusion of the term of commitment established under this section 6 of this Schedule 6A, a Black Start Unit shall commence a new term of commitment under either section 5 or 6 of this Schedule 6A, as applicable.

(ii) Owners of Black Start Units selected to provide Black Start Service after June 6, 2021, in accordance with Schedule 6A, section 4 and electing to recover new or additional Black

Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial capital recovery period based upon the age of the Black Start Unit plus the remaining life of the Black Start equipment. For those Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the initial capital recovery period based upon the age of the Black Start Unit plus the remaining life of the Black Start equipment.

(iii) Black Start Units selected to be Fuel Assured Black Start Units in accordance with Schedule 6A, section 4 and electing to recover new or additional Fuel Assurance Capital Costs or new and additional Fuel Assurance Costs and Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial capital recovery period based upon the age of the Black Start Unit plus the remaining life of the Black Start equipment. For those Fuel Assured Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the initial capital recovery period based upon the age of the Black Start Unit plus the remaining life of the Black Start equipment. For those Fuel Assured Black Start Units that elect to recover new or additional Fuel Assurance Capital Costs, the applicable capital recovery period shall be the fuel assurance capital recovery period based upon the age of the Fuel Assured Black Start Unit .

The Transmission Provider may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Black Start Unit owner shall be eligible to recover any amount of unrecovered Fixed Black Start Service Costs including any amount of unrecovered Fuel Assurance Capital Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice and consent of the Transmission Provider (or its commitment period may be involuntarily terminated pursuant to the section 15 below), provided the Black Start Unit's owner demonstrates to the satisfaction of the Transmission Provider at least one of the following reasons for such termination apply:

a. Black Start Unit retirement or deactivation with at least one year's notice;

b. Expiration of a state, federal, or other governmental agency permit(s) required for Black Start Service with at least one year's notice; or

c. Additional capital is required by the Black Start Unit owner to maintain Black Start Service capability (in which case, the Black Start Unit will apply for Black Start Service selection in accordance with the procedures set forth in Manual 12 and only continue to provide Black Start Service if selected for Black Start Service by the Transmission Provider).

Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs and/or Fuel Assurance Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i) of this Schedule 6A) in excess of the amount that would have been recovered pursuant to Schedule 6A, section 18 during the same period.

6A. Black Start Units which are owned or contracted for by a Transmission Owner to provide Black Start Service as a result of the black start reliability backstop process defined in the PJM Manuals, shall be subject to cost recovery through such Transmission Owner's annual revenue requirement under such Transmission Owner's Tariff, Attachment H, as filed with, and accepted by, FERC under Section 205 of the Federal Power Act and in accordance with Tariff, Part I, section 9, or through such other cost recovery mechanism, provided that such cost recovery mechanism is filed with and accepted by FERC. The relevant Transmission Owner shall commit to provide, or effectuate the provision of, Black Start Service from such a Black Start Unit for the FERC-approved cost recovery period. The Transmission Provider may terminate the commitment with one year advance notice of its intention to the Transmission Owner. Provision of Black Start Service from a Black Start Unit obtained through the black start reliability backstop process defined in the PJM Manuals shall be subject to sections 7 through 13 of this Schedule 6A. The Revenue Requirements, Credits, and Charges provisions contained in sections 16 through 27 of this Schedule 6A, shall not apply to Black Start Units obtained as a result of the black start reliability backstop process defined in the PJM Manuals.

6B. In the event that a Black Start Unit fails to fulfill its commitment established under section 5 to provide Black Start Service, receipt of any Black Start Service revenues associated with the non-performing Black Start Unit shall cease and, for the period of the unit's non-performance, the Black Start Unit owner shall forfeit the Black Start Service revenues associated with the non-performing Black Start Unit that it received or would have received had the Black Start Unit performed, not to exceed revenues for a maximum of one year.

In the event that a Black Start Unit fails to fulfill its commitment established under section 6 above, such unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i) of this Schedule 6A) in excess of the amount that would have been recovered pursuant to section 18 of this Schedule 6A during the same period, but such unit remains eligible to establish a new commitment under section 5 or 6 of this Schedule 6A. Provided, however, Black Start Units that are selected to provide Black Start Service after June 6, 2021, pursuant to Schedule 6A, section 6 that subsequently transition from the Capital Cost Recovery Rate to the Base Formula Rate shall have a lifetime commitment and can only terminate for a reason specified in Schedule 6A, section 6(ii).

<u>**Performance Standards and Outage Restrictions**</u>

7. In addition to the performance capabilities set forth in the PJM Manuals, Black Start Units must have the capabilities listed below. These capabilities must be demonstrated in accordance with the criteria set forth in the PJM manuals and will remain in effect for the duration of the commitment to provide Black Start Service.

a. A Black Start Unit must be able to close its output circuit breaker to a dead (de-energized) bus within the time specified in the PJM Manuals.

b. A Black Start Unit must be capable of maintaining frequency and voltage under varying load.

c. A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

d. A Fuel Assured Black Start Unit must meet the fuel assurance requirements as specified in the PJM Manuals.

8. Each owner of Black Start Units or Black Start Plants must maintain procedures for the start-up of the Black Start Units.

9. If a Black Start Unit is a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, this ability must be demonstrated in accordance with the criteria set forth in the PJM manuals.

10. No more than one Black Start Unit at a Black Start Plant may be subject to a Generator Planned Outage or Generator Maintenance Outage at any one time without written approval of the Transmission Provider and the Transmission Owner in the Zone receiving Black Start Service from the Black Start Plant. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not selected for providing Black Start Service in accordance with this Schedule 6A, section 4 and the PJM Manuals may be substituted for a Black Start Unit that is subject to a Generator Planned Outage to permit a concurrent planned outage of another critical Black Start Unit at the same Black Start Plant. The Black Start Unit used as a substitute shall not receive compensation for additional capital expenditures to qualify for Black Start Service, will not increase the current Black Start Unit capital recovery commitment period, must be connected at the same voltage level and cranking path, must be similar age as the current Black Start Unit, must provide equivalent Black Start Unit Capacity, and must have had a valid annual test within the previous 13 months. Black Start Unit substitutions may be permitted for reasons other than Generator Planned Outages if requested by the Black Start Unit owner and if approved by the Transmission Provider; provided, however, all requests for Black Start Unit substitutions must be supported by documentation and information demonstrating operational or technical reasons for the substitution satisfactory to the Transmission Provider and may only occur once within a 12-month period.

11. Concurrent planned outages at multiple Black Start Plants within a zone may be restricted based on Transmission Owner requirements for Black Start Service availability. Such restrictions must be predefined and approved by Transmission Provider in accordance with the PJM manuals.

Testing

12. To verify that they can be started and operated without being connected to the Transmission System, Black Start Units shall be tested annually in accordance with the Tariff and the PJM Manuals. Fuel Assured Black Start Units that are dual fuel must conduct an annual test on both fuels. The Black Start Unit owner shall determine the time of the annual test.

13. Compensation under this Schedule 6A for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's minimum run time at the higher of the unit's cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

14. All Black Start Units must have a successful annual test on record with the Transmission Provider within the preceding 13 months. A Black Start Unit receiving revenues under Section 5 or Section 6 above that does not have a successful annual test on record with the Transmission Provider within the preceding 13 months will not qualify to receive Black Start Service revenues. A Fuel Assured Black Start Unit that stores fuel on-site and fails in any month to store the fuel and non-fuel consumables needed to meet its fuel assurance run hour requirements except for allowable conditions specified in the PJM Manuals, and except when the Fuel Assured Black Start Unit can also operate independently on 2 or more interstate pipelines, does not qualify to receive Black Start revenues in that month.

15. If a Black Start Unit fails the annual test, the unit may be re-tested within a ten-day period without financial penalty. If the Black Start Unit does not successfully re-test within that ten-day period, monthly Black Start Service revenues under this Schedule 6A will be forfeited by that unit from the time of the first unsuccessful test until such time as the unit passes an annual test. If the Black Start Unit owner does not make the necessary repairs to enable the Black Start Unit to pass the annual test within 90 days of the due date for the annual test pursuant to section 14 above, the Black Start Unit will immediately cease to qualify as a Black Start Unit and, if applicable, will have failed to fulfill its commitment pursuant to section 5 or section 6 above, whichever is applicable, of this Schedule 6A and will be subject to the additional forfeiture of revenues set forth in section 6B of this Schedule 6A. The 90 day period may be extended up to 1 year by the Transmission Provider in accordance with the PJM Manuals. If the 90 day period is extended, the Black Start Unit owner will continue to forfeit all revenues starting in the month of the first failed test until the Black Start Unit has demonstrated to the Transmission Provider that a successful test has been completed.

Revenue Requirements

16. A Black Start Unit Owner's annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider bill for Black Start Service charges and credits.

17. Black Start Service revenue requirements for each Black Start Unit shall be based, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either section 5 or 6 of this Schedule 6A, as applicable, or (ii) the formula rates set forth in section 18 of this Schedule 6A for the commitment term set forth in section 5 or 6 of this Schedule 6A as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation.

17A. Annual Review for all Black Start Units

Requests for Black Start Service revenue requirements and for changes to the Black Start Service revenue requirements must be submitted to the Market Monitoring Unit for review and analysis, with supporting data and documentation, pursuant to Tariff, Attachment M–Appendix, section III and the PJM Manuals, with a copy to the Office of the Interconnection, by no later than May 3 of each year. The Market Monitoring Unit and the Black Start Unit owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. By no later than May 21 of each year, the Black Start Unit owner shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees or disagrees with the Market Monitoring Unit's determination of the level of each component included in the Black Start Service revenue requirements. The Black Start Unit owner may also submit Black Start Service revenue requirements that it chooses to the Office of the Interconnection by no later than May 21 of each year, provided that (i) it has participated in good faith with the process described in this section and in Tariff, Attachment M-Appendix, section III (ii) the Black Start Service revenue requirements are no higher than the level defined in any agreement reached by the Black Start Unit owner and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the Black Start Service revenue requirements are accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and PJM Manuals.

The Office of the Interconnection shall determine whether to accept the values submitted by the Black Start Unit owner subject to the requirements of the Tariff and the PJM Manuals by no later than May 27. If the Office of the Interconnection does not accept the values submitted by the Black Start Unit owner in such case, the Black Start Unit owner may file its proposed values with the Commission for approval. Pursuant to Tariff, Attachment M-Appendix, section III, if the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Unit owner to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission. The annual calculation of Black Start Service revenue requirements shall become effective on June 1 of each year, except that no change to a Black Start Service revenue requirement shall become effective until the existing revenue requirement has been effective for at least twelve months. Notwithstanding the foregoing, the deadlines set forth in this section 17 shall not apply to a Black Start Unit owner's election to select a new method of recovery for its Fixed BSSC.

17B. Initial Review for New Black Start Units or existing Black Starts Units that require Fuel Assured Capital Cost

Requests for new Black Start Service revenue requirements and/or Fuel Assured Capital Costs must be submitted to the Market Monitoring Unit for review and analysis, with supporting data and documentation, pursuant to Tariff, Attachment M–Appendix, section III and the PJM Manuals, with a copy to the Office of the Interconnection, by no later than 90 days after entering Black Start Service or qualifying to be a Fuel Assured Black Start Unit. The Market Monitoring Unit and the Black Start Unit owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements by no later than 90 days after the Black Start Unit owner's submittal of final black start capital costs (if applicable), variable black start costs, and fuel storage cost documentation. By no later than 90 days of the Black Start Unit owner's submittal of final black start cost documentation, the Market Monitoring Unit shall calculate the new Black Start Unit's annual revenue requirement and submit it to the Office of the Interconnection and the Black Start Unit owner. If more than three Black Start Unit owners submit documentation within a 90-day period, the Market Monitoring Unit shall complete the review of the first three submittals within 90 days and the next set of three within the following three months and so on until all are complete. The Black Start Unit owner shall notify the Office of the Interconnection and the Market Monitoring Unit in writing if it disagrees with the Market Monitoring Unit's determination of the level of any component included in the Black Start Service revenue requirements within 7 days after the Market Monitoring Unit's submittal of the annual revenue requirement to the Office of the Interconnection. The Black Start Unit owner shall also submit Black Start Service revenue requirements that it proposes to the Office of the Interconnection provided that (i) it has participated in good faith with the process described in this section and in Tariff, Attachment M-Appendix, section III; (ii) the Black Start Service revenue requirements are no higher than the level defined in any agreement reached by the Black Start Unit owner and the Market Monitoring Unit that resulted from the foregoing process; and (iii) the Black Start Service revenue requirements are accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and PJM Manuals.

The Office of the Interconnection shall determine whether to accept the values submitted by the Black Start Unit owner subject to the requirements of the Tariff and the PJM Manuals by no later than 30 days after its receipt of the Black Start Unit owner's written notice of a disagreement. If the Office of the Interconnection does not accept the values submitted by the Black Start Unit owner in such case, the Black Start Unit owner may file its proposed values with the Commission for approval. Pursuant to Tariff, Attachment M–Appendix, section III, if the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Unit owner to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission. The annual calculation of Black Start Service revenue requirements shall become effective the day the unit enters Black Start Service or becomes fuel assured.

18. The formula for calculating a generator's annual Black Start Service revenue requirement is:

{(Fixed BSSC) + (Variable BSSC) + (Training Costs) + (Fuel Storage Costs)} * (1 + Z)

For units that have the demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the formula is revised to:

(Training Costs) * (1+ Z)

Where:

Fixed BSSC

Black Start Units with a commitment established under section 5 of this Schedule 6A shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following Base Formula Rate:

<u>Base Formula Rate:</u>

Net CONE * Black Start Unit Capacity * X

Where:

"Net CONE" is the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE Area where the Black Start Unit is located.

"Black Start Unit Capacity" is either: (i) the Black Start Unit's installed capacity, expressed in MW, for those Black Start Units which are not Fuel Assured Black Start Units that are Generation Capacity Resources; (ii) the awarded MWs in the Transmission Provider's request for proposal process under the PJM Manuals, for those Black Start Units, which are not Fuel Assured Black Start Units, that are Energy Resources; (iii) the Fuel Assured Black Start Unit's installed capacity for fuel assured non-intermittent Capacity Resources; or (iv) the monthly 90% confidence MW value calculated by the Transmission Provider for fuel assured intermittent or hybrid Capacity Resources. The 90% confidence MW value is calculated using Black Start Unit historical data to determine the hourly MW value the resource can provide each day in each month for 16 hours, which need not be continuous. The hourly MW value is then iterated until the confidence level of the unit providing the MW value on a monthly basis for 16 hours is 90%.

"X" is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For non-fuel assured Black Start Units with a commitment established under ~~section 5 of this~~ Schedule 6A, X shall be .01 for Hydro units, .02 for CT units. For fuel assured Black Start Units with a commitment established under ~~section 5 of this~~ Schedule 6A, X shall be .02 for all units.

Black Start Units with a commitment established under section 6 above shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with one of the following formulas, as applicable:

Capital Cost Recovery Rate – NERC-CIP Specific Recovery

(Net Cone * Black Start NERC-CIP Unit Capacity * X) + (Incremental Black Start NERC-CIP Capital Costs * CRF) + (Fuel Assurance Capital Costs * CRF)

Where:

"Net Cone" is the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE are where the Black Start Unit is located.

"Black Start NERC-CIP Unit Capacity" is the Black Start Unit's installed capacity, expressed in MW, but, for purposes of this calculation, capped at 100 MW for Hydro units, or 50 MW for CT units.

"Incremental Black Start NERC-CIP Capital Cost" are those capital costs documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a Black Start Unit to maintain compliance with mandatory Critical Infrastructure Protection Reliability Standards (as approved by the Commission and administered by the applicable Electric Reliability Organization).

"Fuel Assurance Capital Costs" are the new or additional capital costs documented by the owner for the installation of equipment necessary for the unit to meet the fuel assurance criteria specified in the PJM manuals.

"CRF" or "Capital Recovery Factor" is equal to the levelized CRF as set forth in the applicable CRF table posted on the PJM website in accordance with Tariff, Schedule 6A, section 18 and Manual 15.

A Black Start Unit may elect to terminate forward cost recovery under this Capital Cost Recovery Rate – NERC-CIP Specific Recovery at any time and seek cost recovery under the Capital Cost Recovery Rate, pursuant to the terms and conditions set forth below.

Capital Cost Recovery Rate

(FERC-approved rate) + (Incremental Black Start Capital Costs * CRF) + (Fuel Assurance Capital Costs * CRF)

Where:

"FERC-approved rate" is the Black Start Unit's current FERC-approved recovery of costs to provide Black Start Service, if applicable. To the extent that a Black Start Unit owner is currently recovering black start costs pursuant to a FERC-approved rate, that cost recovery will be included as a formulaic component for calculating the Black Start Unit's annual revenue requirement pursuant to this section 18. However, under no circumstances will PJM or the Black Start Unit owner restructure or modify that existing FERC-approved rate without FERC approval.

"Incremental Black Start Capital Costs" are the new or additional capital costs documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Unit owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit. However, Incremental Black Start Capital Costs shall not include any capital costs that the Black Start Unit owner is recovering for that unit pursuant to a FERC-approved recovery rate.

"Fuel Assurance Capital Costs" are the new or additional capital costs documented by the owner for the installation of equipment necessary for the unit to meet the fuel assurance criteria specified in the PJM manuals. However, Fuel Assurance Capital Costs shall not include any capital costs that the Fuel Assured Black Start Unit owner is recovering for that unit pursuant to a FERC-approved recovery rate.

The Capital Recovery Factor ("CRF") is equal to the Levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service.

The CRF applicable to Black Start Capital Costs of Black Start Units selected for Black Start Service prior to June 6, 2021, shall continue to be determined in accordance with the following table:

Age of Black Start Unit	Term of Black Start Commitment	Levelized CRF
1 to 5	20	0.1180
6 to 10	15	0.1348
11 to 15	10	0.1767
16+	5	0.3097

The CRF applicable to Black Start Capital Costs and/or for Fuel Assurance Capital Costs, of Black Start Units selected for Black Start Service after June 6, 2021, shall be updated annually on March 1 (if March 1 is not a Business day then the first Business Day after March 1) for (i) federal income tax rates as utilized by the U.S. Internal Revenue Service in effect at the time of the annual CRF update; (ii) average state tax rate; and (iii) debt interest rates and shall be posted on the PJM website by March 31 each year as shown in the table below. Interested parties shall have until April 15 of each year to contest PJM's calculation of the annual CRF value before it becomes effective on June 1 of each year.

PJM determines annual CRF inputs	March 1 (if March 1 is not a Business day then the first Business Day after March 1)
PJM posts annual CRF	March 31
Deadline for contesting annual CRF	April 15
Annual revenue requirement calculation	May 3 through May 27
Annual revenue requirement with CRF in effect	June 1

The CRF values shall be calculated for a recovery period based on the age of the Black Start Unit using the equation below:

$$CRF = \frac{r\,(1+r)^{N}\left[1-\frac{sB}{\sqrt{1+r}}-s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{m_j}{(1+r)^{j}}\right]}{(1-s)\sqrt{1+r}\left[(1+r)^{N}-1\right]}\ldots$$

Where:

Formula Symbol	**Description**
r	After Tax Weighted Average Cost of Capital (ATWACC), which equals (equity percentage)(cost of equity) + (debt percentage)(debt interest rate)(1 – effective tax rate)
s	Effective Tax Rate, which equals (1 – state tax rate)(federal tax rate) + state tax rate
B	Bonus depreciation percent in effect at the Black Start Unit in-service date
N	Cost recovery period based on the age of the unit in years, as established in the Age of Unit/Applicable Recovery Period table below
L	The lesser of N or 16 years

M_j	Modified Accelerated Cost Recovery System (MACRS) depreciation

The following assumptions are used in the calculation:

The current federal tax and depreciation rates are as established by U.S. Internal Revenue Service;

The state tax rate is an average of the income tax rates for all the states in the PJM Region;

The capital investment necessary to make a unit qualify for Black Start Service is made up of 50 percent equity;

The capital investment necessary to make a unit qualify for Black Start Service is made up of 50 percent debt;

The debt interest rate is based on the most recent Net CONE quadrennial review after-tax weighted average cost of capital (ATWACC) and shall be updated as follows:

The debt interest rate will be updated during the Net CONE quadrennial review; and

If the 2-year change in the Moody Utility Index for bonds rated Baa1 is more than 200 basis points, this change will be added to the interest rate used in the most recent Net CONE quadrennial review and will be used as the current year's debt interest rate.

The debt term is equal to the applicable recovery period specified in the Age of Unit/Applicable Recovery Period table below; and

The cost of equity shall be equal to an after tax internal rate of return on equity of 12%.

Any changes to the debt and equity percentages and after tax internal rate of return on equity components stated above shall be included in revisions to this section 18.

Age of the Unit (years)	Incremental Black Start Capital Costs Applicable Recovery Period (years)	Fuel Assurance Capital Costs Recovery Period (years)
1-5	20	20
6-10	15	15
11-15	10	10
16+	5	10

In those circumstances where a Black Start Unit owner has elected to recover Incremental Black Start Capital Costs and/or Fuel assurance Capital Costs, in addition to a FERC-approved recovery rate, its applicable term of commitment shall be the greater of: (i) the FERC-approved recovery period, or; (ii) the applicable term of commitment as set forth in the Age of Unit/Applicable Recovery Period table above.

After a Black Start Unit has recovered its allowable Incremental Black Start Capital Costs, Incremental Black Start NERC-CIP Capital Costs, and/or Fuel assurance Capital Costs as provided by the applicable Capital Cost Recovery Rate, and has satisfied its applicable commitment period required under section 6 of this Schedule 6A, the Black Start Unit shall be committed to providing black start in accordance with section 5 of this Schedule 6A and calculate its Fixed BSSC in accordance with the Base Formula Rate.

Variable BSSC

All Black Start Units shall calculate Variable BSSC or "Variable Black Start Service Costs" in accordance with the following formula:

Black Start Unit O&M * Y

Where:

"Black Start Unit O&M" are the operations and maintenance costs attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost Development Guidelines set forth in the PJM Manuals. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by unit.

"Y" is 0.01, unless a higher or lower value is supported by the documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start Unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost Development Guidelines in the PJM Manuals.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no variable costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

Black Start Units with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid may receive NERC compliance costs associated with providing Black Start Service in addition to the formula above, if approved in accordance with the procedures in section 17 of this Schedule 6A.

Training Costs:

All Black Start Units shall calculate Training Costs in accordance with the following formula:

50 staff hours/year/plant*75/hour

Fuel Storage Costs:

Black Start Units that store liquefied or compressed natural gas, propane, or oil on site shall calculate Fuel Storage Costs in accordance with the following formula:

{MTSL + [(# Run Hours) * (Fuel Burn Rate)]} *
(12 Month Forward Strip + Basis) * (Bond Rate)

Where:

Run Hours are the actual number of hours a Transmission Provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less.

"Fuel Burn Rate" is actual fuel burn rate for the Black Start Unit.

"12-Month Forward Strip" is the average of forward prices for the fuel burned in the Black Start Unit traded the first Business Day on or following April 1.

"Basis" is the transportation costs from the location referenced in the forward price data to the Black Start Unit plus any variable taxes.

"Bond rate" is the value determined with reference to the Moody's Utility Index for bonds rated Baa1 reported the first Business Day on or following April 1.

"MTSL" is the "minimum tank suction level" and shall apply to oil fired Black Start Units' storage tanks that have an unusable volume of oil. In the case where a Black Start Unit shares a common fuel tank, the Black Start Unit will be eligible for recovery of the Black Start Energy Tank Ratio of the MTSL in its fuel storage calculation.

Black Start Energy Tank Ratio = {(Fuel Burn Rate * Minimum Run Hours) / (Tank Capacity – MTSL)}

The MTSL fuel storage calculation shall be as follows:
{(Black Start Energy Tank Ratio * MTSL) + [(#Run Hours) * (Fuel Burn Rate)]} * (12 Month Forward Strip + Basis) * (Bond Rate)

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no associated fuel storage costs and the value for FSC shall be zero.

Z

Z shall be an incentive factor solely for Black Start Units with a commitment established under section 5 above and shall be ten percent for non-fuel assured Black Start Units and twenty percent for Fuel Assured Black Start Units. For those Black Start Units that elect to recover new or additional Black Start or Fuel Assurance Capital Costs under section 6 above, the incentive factor, Z, shall be equal to zero.

Every five years, PJM shall review the formula and its costs components set forth in this section 18, and report on the results of that review to stakeholders.

19. Transmission Provider or its agent shall have the right to independently audit the accounts and records of each Black Start Unit that is receiving payments for providing Black Start Service.

20. PJM shall notify its Members when a Black Start Unit seeks to recover new or additional Black Start NERC-CIP Capital Costs under section 18 of this Schedule 6A no later than thirty (30) days prior to the effective date of the recovery. At the written request of a PJM Member, made simultaneously to the Market Monitoring Unit and PJM, with notice to the Black Start Unit owner, the Market Monitoring Unit shall make available to the affected PJM Member for inspection at the offices of the Market Monitoring Unit, all data supporting the requested new or additional NERC-CIP specific Capital Costs. The Black Start Unit owner may elect to attend this review. In all cases, the supporting data is to be held confidential and may not be distributed.

21. The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital Costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit.

Credits

22. For existing Black Start Units, monthly credits are provided to Black Start Unit owners that submit to the Transmission Provider their annual revenue requirements established pursuant to section 17A of this Schedule 6A. The generator's monthly credit is equal to 1/12 of its annual Black Start Service revenue requirement for eligible critical Black Start Units. For new Black Start Unit owners, monthly credits will be held by the Office of the Interconnection in a non-interest bearing account until the Office of the Interconnection, or the Commission as applicable, accepts the owner's annual revenue requirement pursuant to section 17B of this Schedule 6A. New Black Start Unit owners will begin to receive monthly credits, including any monthly credits held by the Office of the Interconnection back to the date the unit enters Black Start Service and any required estimated annual revenue requirement true up after the Office of the Interconnection, or the Commission as applicable, accepts the new Black Start Unit owner's annual revenue requirement.

22A. For Fuel Assured Black Start Units that are recovering Fuel Assurance Capital Costs, pursuant to section 17B of this Schedule 6A, shall have its monthly credits reduced, but not less than zero, by the positive net value of the Day-ahead Energy Market and Real-time Energy Market revenues from being committed using the fuel assurance fuel as further described in the PJM manuals minus the cost of running on that fuel. The Black Start Unit's monthly credits shall not be increased. For Fuel Assured Black Start Units that are recovering Fuel Assurance Capital Cost and the Fuel Assurance Capital Costs increased the Installed Capacity Rating (ICAP) of the unit, monthly credits shall be reduced, but not less than zero, by the monthly capacity revenues for the increased ICAP. Monthly credits will only be reduced during the Fuel Assurance Capital Cost recovery period.

23. Revenue requirements for jointly owned Black Start Units will be allocated to the owners based on ownership percentage.

24. Transmission Provider shall not compensate generators for Black Start Service unless they meet the Transmission Provider criteria for Black Start Service and the criteria for Black Start Service in the Applicable Standards and provide Transmission Provider with all necessary data in accordance with this Schedule 6A and the PJM manuals.

Charges

25. Zonal rates will be based on Black Start Service capability or share of generation units designated by the Transmission Provider and allocated to network service customers and point-to-point reservations. Zonal rates will include estimated annual revenue requirements for new Black Start Units from the date the units enter Black Start Service to last day of the month preceding the Office of the Interconnection's acceptance of the unit's annual revenue requirement. The estimated annual revenue requirement will be based on the Black Start Unit owner's best estimate at the time the unit enters Black Start Service. Any estimated annual revenue requirement true up will be included in the monthly bill after the Office of the Interconnection accepts the new Black Start unit's annual revenue requirement.

26. Revenue requirements for Black Start Units designated by the Transmission Provider as critical (regardless of zonal location) will be allocated to the receiving Transmission Owner's zone. Black Start Units that are shared and designated to serve multiple zones will have their annual revenues allocated by Transmission Owner designated critical load percentage.

27. Purchasers of Black Start Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner Monthly Black Start Service Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner Monthly Black Start Service Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the monthly share of Black Start Service revenue requirements for each generator nominated by the Transmission Owners in that zone.

Total Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the Zonal Generation Owner Monthly Black Start Service Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Tariff, Part I, section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of the month (not curtailed by PJM) divided by the number of hours in the day.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region on a megawatt basis, exclusive of such use by Network Customers and Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 6A.

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Tariff, Attachment K-Appendix, section 2.

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

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

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

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

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

3.2.2 Regulation.

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

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

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

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

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

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

Estimated opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

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

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

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

Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

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

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the Regulation market performance-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

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

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

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

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

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

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

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

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

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Reserve Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market.

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

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

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

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

(A + B) - C

Where:

A = Start-up Costs

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

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

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

D – (E + F)

Where:

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

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

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

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Tariff, Attachment K-Appendix, section 3.2.3(p) below, 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. Allocation to real-time load share under this subsection (b) shall not apply to Direct Charging Energy.

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

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

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

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

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

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

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

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

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Tariff, Attachment K-Appendix, 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 ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) excluding Direct Charging Energy), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Tariff, Attachment K-Appendix, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black

Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

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

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

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

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources) costs for generation resources.

Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and less the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

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

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is reduced or suspended (or, for Energy Storage Resource Model Participants, the charging of which is increased) at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

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

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

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

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) -

(C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

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

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

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

(f-4) A Market Seller of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource 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 or solar generating units, Hybrid Resource or Energy Storage Resource as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-5) If a Market Participant of an Energy Storage Resource Model Participant believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. 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 Participant 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-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section (f-4).

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

(A x B) - C

Where:

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

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

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

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

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

Where:

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

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

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

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

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-~~5~~6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-~~5~~6)(iii) or (B) zero.

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

(g) The sum of the foregoing credits in Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section 3.2.3(f-4), plus any cancellation fees paid in accordance with Tariff, Attachment K-Appendix, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

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

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

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

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

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

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

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

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

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

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

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

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

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

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

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

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

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

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

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

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

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

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

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

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

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

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

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the dispatch signal and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the dispatch LMP Desired MW for each Real-time Settlement Interval.

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

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

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

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

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

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

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

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

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

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

(o-1) Dispatchable Economic Load Response Participant 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 Tariff, Attachment K-Appendix, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. Allocation to real-time load share under this subsection (p) shall not apply to Direct Charging Energy. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, section 1.11.6, the Office of the Interconnection shall allocate the charges to the ratio share of real-time load plus export transactions.

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

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

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

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

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

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

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

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

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with section 3.2.3(p). Allocation to real-time load share under this subsection (q)(i) shall not apply to Direct Charging Energy.

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Tariff, Attachment K-Appendix, section 3.2.3(q)(i). 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). Allocation to real-time load share under this subsection (q)(ii) shall not apply to Direct Charging Energy.

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

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

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

3.2.3A Synchronized Reserve.

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

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

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

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

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

Where:

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

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

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

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

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

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

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

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

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve

Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

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

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

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

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

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum Synchronized Reserve Requirement shall be $2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Synchronized Reserve are warranted for subsequent Delivery Year(s).

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

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

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

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

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

$(A \times B) – C$

Where:

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

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

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

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Synchronized Reserve].

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

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

Where:

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

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional Condense Energy Use in excess of day-ahead Condense Energy Use in real-time multiplied by A] plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals].

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

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

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

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

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

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

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

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

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

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

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

(A + B + C + D) – (E + F + G + H)

Where:

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

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

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

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

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

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

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

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

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

(g) [Reserved for future use]

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

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve the resource was directed to deploy, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. For each Real-time Settlement Interval where there is not a Synchronized Reserve Event, the megawatts that will be charged shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, or the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

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

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following

January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

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

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

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

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

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

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

Where:

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

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

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

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

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

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

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

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

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

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

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

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

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum Primary Reserve Requirement shall be $2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Primary Reserve are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

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

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

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

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

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

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

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

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

(zero) – (A + B + C + D)

Where:

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

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

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

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

(e) [Reserved for future use]

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

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

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

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

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

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

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

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

Where:

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

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

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

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

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

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

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

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

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

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

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

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

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum 30-minute Reserve Requirement shall be $2000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for 30-minute Reserve are warranted for subsequent Delivery Year(s).

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

Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

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

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

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

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

(A x B) – C

Where:

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

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

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

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Secondary Reserve].

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

(A x B) – C

Where:

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

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

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

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

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

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

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

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

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

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

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

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

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

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

$(A + B) – (C + D + E + F)$

Where:

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

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

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

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

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

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

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

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

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

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

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

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

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

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

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

3.2.3A.02 Operating Reserve Demand Curves

(a) Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet reliability requirements in light of supply and demand uncertainties. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with subsection (b) and the PJM Manuals.

(b) Methodology for Establishing Operating Reserve Demand Curves

For each three-month season, Winter (December through February), Spring (March through May), Summer (June through August), and Fall (September through November), and for each time-of-day block set forth in the PJM Manuals, the Office of the Interconnection shall establish Operating Reserve Demand Curves for each Reserve Zone or Reserve Sub-zone as follows:

(i) Each Operating Reserve Demand Curve shall be plotted on a graph on which megawatts of reserve is on the x-axis and price is on the y-axis;

(ii) The Operating Reserve Demand Curve for each Reserve Zone or Reserve Sub-zone shall be plotted by combining (i) a straight horizontal line starting from point (1) on the y-axis to point (2), (ii) a straight vertical line connecting points (2) and (3), and (iv) a curved line from point (3) to the x-axis, where:

(A) Point (1) is the point on the y-axis(price) equal to the Reserve Penalty Factor for the minimum reserve requirement for the subject reserve requirement (i.e., the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement, or the Minimum Synchronized Reserve Requirement);

(B) Point (2) has the y-axis coordinate of point (1) and the x-axis coordinate of the applicable minimum reserve requirement as determined for the Reserve Zone or Reserve Sub-zone in accordance with the PJM Manuals;

(C) Point (3) has the x-axis coordinate of the applicable minimum reserve requirement and the y-axis coordinate resulting from multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring an infinitesimal amount of additional MW of reserves beyond the minimum reserve requirement; and

(D) From point (3) to the x-axis, first, the Office of the Interconnection develops a curve starting at point (3). The shape of the curve will be determined by multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring each additional MW of reserves beyond the minimum reserve requirement until the resulting product falls below $0.01/MWh at which point the curve will intersect with the x-axis. These probabilities are calculated from an empirical distribution of data from a rolling three-calendar year period of the following supply and demand uncertainties, using a 30-minute time horizon for clearing Primary Reserves and Synchronized Reserves and a 60-minute time horizon for clearing 30-minute Reserves: load forecast error, wind forecast error, solar forecast error, and forced outages of thermal units, and, for the Operating Reserve Demand Curves for 30-minute Reserves only, net interchange forecast error, all as described in the PJM Manuals. The empirical distribution also accounts for the Regulation requirement, expressed in effective megawatts, that PJM has established for each hour within that time-of-day block, by reducing the magnitude of the above uncertainties by the requirement.

The Office of the Interconnection will post each Operating Reserve Demand Curve used to clear reserve markets.

(c) Annual Update of Operating Reserve Demand Curves

On an annual basis, the Office of the Interconnection shall update the determination of the probability of falling below the applicable minimum reserve requirement, including each uncertainty, to account for the most recent calendar year's data, in accordance with the PJM Manuals, and post revised Operating Reserve Demand Curves by April 1. The revised Operating Reserve Demand Curves shall become effective June 1, coincident with the start of the next Delivery Year.

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 a steam-electric generating unit, an Energy Storage Resource Model Participant, a Hybrid Resource, or a combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output (or the level of Energy Storage Resource Model Participant charging withdrawals) requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the

Interconnection's signals and the generating unit's expected output level (or the level of Energy Storage Resource Model Participant charging withdrawals) if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

AG equals the actual output of the unit;

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

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

URTLMP equals the real time LMP at the unit's bus; and where UB - URTLMP shall not be negative.

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

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

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of 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 Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) 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 Tariff, Attachment K-Appendix, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Tariff, Attachment K-Appendix, section 5.

3.2.6 Emergency Energy.

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

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

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

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

3.2.7 Billing.

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

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

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules.

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

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

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

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

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

~~(i) Turn Down Ratio;~~

~~(ii) Minimum Down Time;~~

~~(iii) Minimum Run Time;~~

~~(iv) Maximum Daily Starts;~~

~~(v) Maximum Weekly Starts.~~

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

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts;

(vi) Maximum Run Time;

(vii) Start-up Time; and

(viii) Notification Time.

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

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

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

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

(d) [Reserved]

(e) [Reserved]

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

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

~~markets. For generating units having the ability to operate on multiple fuels, Market Sellers may submit a parameter limited schedule associated with each fuel type.~~

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(ii) Period Exceptions and Persistent Exceptions. Market Sellers must submit period exception and persistent exception requests to the Market Monitoring Unit and the Office of the Interconnection by no later than the February 28 immediately preceding the twelve month period from June 1 to May 31 during which the exception is requested to commence. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period exception or persistent exception request, and if the exception requested is based on new physical operational limits for the unit for which some or all historical operating data is unavailable, the generating unit may also submit technical information about the physical operational limits for exceptions of the unit to support the requested parameters. The Market Monitoring Unit shall evaluate such request in accordance with the process set forth in Tariff, Attachment M-Appendix, section II.B. A Market Seller (i) must submit a parameter limited schedule value consistent with an agreement with the Market Monitoring Unit under such process or (ii) if it has not agreed with the Market Monitoring Unit on the parameter limited schedule value, may submit its own value to the Office of the Interconnection and to the Market Monitoring Unit, by no later than April 8. Each exception request must indicate the expected duration of the requested exception including the termination date thereof. The proposed parameter limited schedule value submitted by the Market Seller is subject to approval of the Office of the Interconnection pursuant to the requirements of the Tariff and the PJM Manuals. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the exception request. After it has completed its evaluation of the exception request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the exception request is approved or denied, by no later than April 15. The effective date of the exception, if approved by the Office of the Interconnection, shall be no earlier than June 1 of the applicable Delivery Year. The Office of the Interconnection's determination for an exception shall continue for the period requested and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

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

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

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

~~(3)~~ (1) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply. ~~for the 2016/2017 Delivery Year and subsequent Delivery Years,~~

~~(4) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which adjusted unit-specific values have been approved by PJM, the Base Capacity Resource adjusted unit-specific values shall apply for the 2018/2019 and 2019/2020 Delivery Years, and~~

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

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

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

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

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has

delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Operating Agreement, section 18.17.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Tariff, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the Market Monitoring Unit using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the Market Monitoring Unit from a third party which is not, to the Office of the Interconnection's or Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. **Disclosure to FERC and CFTC**:

1. Notwithstanding anything in this section I to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC") or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in section I.B.

D. **Disclosure to Authorized Commissions**:

1. Notwithstanding anything in this section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market

Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. [Reserved]

II. <u>DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION</u>

A. <u>Offer Price Caps</u>:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Operating Agreement, Schedule 1, section 6.4.2and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2) included in the Offer Price Cap of a generating unit in order to ensure

that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Operating Agreement, Schedule 2.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Operating Agreement, Schedule 1, section 6.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2 is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Operating Agreement, Schedule 1, section 6.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. <u>Minimum Generator Operating Parameters</u>:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Operating Agreement, Schedule 1, section 6.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6 and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Tariff, Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Tariff, Attachment DD, section 6.6.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under Tariff, Attachment DD.

3. Through the 2024/2025 Delivery Year, the Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Tariff, Attachment DD, section 6.6(b). If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORd that may be used in a Sell Offer for RPM Auctions held prior to the

date on which the final EFORds used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORd to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the

Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Tariff, Attachment DD, section 5.6.6, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in section II.C.4 above, or (iii) through the 2024/2025 Delivery Year, a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level determined under section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Tariff, Attachment DD, section 6.6.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Tariff, Attachment DD, section 6.6(g), to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Tariff, Attachment DD, section 6.6(i), and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. Unit Specific Minimum Sell Offers:

1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, section~~s 5.14(h) and~~ 5.14(h-2~~1~~), the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.

2. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

E. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Tariff, Attachment DD,

section 6.7(d), the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Tariff, Attachment DD, section 6.5, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. Data Submission:

Pursuant to Tariff, Attachment DD, section 6.7, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Tariff, Attachment DD, section 6.7(c) and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Tariff, Attachment DD, section 6.7, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in Tariff, Attachment DD, section 6.7(d).

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Tariff, Attachment DD, section 6.8(d), and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Tariff, Attachment DD, section 6.7(d)(ii). The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Tariff, Schedule 6A and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Tariff, Part V from the Office of the Interconnection forwarded pursuant to Tariff, Part V, section 113.1, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (or, if applicable, its designated agent) if a market power issue has been identified. The Market Monitoring Unit shall provide such notice by the following date: (a) May 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between January 1 and March 31; (b) August 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between April 1 and June 30; (c) November 30 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between July 1 and September 30; or (d) February 28 of the following calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between October 1 and December 31. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Tariff, Part V, section 114 and Tariff, Part V, section 119.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.
3B(h), discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the paralelle provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.3B9H).

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Operating Agreement, Schedule 1, section 5.2.1(b) and Tariff, Attachment K-Appendix, section 5.2.1(b), including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Tariff, Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

ATTACHMENT Q

CREDIT RISK MANAGEMENT POLICY

I. INTRODUCTION

It is the policy of PJM that prior to an entity participating in any PJM Markets or in order to take Transmission Service, the entity must demonstrate its ability to meet the requirements in this Attachment Q. This Attachment Q also sets forth PJM's authority to deny, reject, or terminate a Participant's right to participate in any PJM Markets in order to protect the PJM Markets and PJM Members from unreasonable credit risk from any Participant's activities. Given the interconnectedness and overlapping of their responsibilities, PJM Interconnection, L.L.C. and PJM Settlement, Inc. are referred to both individually and collectively herein as "PJM."

PURPOSE

PJMSettlement is the counterparty to transactions in the PJM Markets. As a consequence, if a Participant defaults on its obligations under this Attachment Q, or PJM determines a Participant represents unreasonable credit risk to the PJM Markets, and the Participant does not post Collateral, additional Collateral or Restricted Collateral in response to a Collateral Call, the result is that the Participant represents unsecured credit risk to the PJM Markets. For this reason, PJM must have the authority to monitor and manage credit risk on an ongoing basis, and to act promptly to mitigate or reduce any unsecured credit risk, in order to protect the PJM Markets and PJM Members from losses.

This Attachment Q describes requirements for: (1) eligibility to be a Market Participant, (2) establishment and maintenance of credit by Market Participants, and (3) collateral requirements and forms of credit support that will be deemed as acceptable to mitigate risk to any PJM Markets.

This Attachment Q also sets forth (1) PJM's authority to monitor and manage credit risk that a Participant may represent to the PJM Markets and/or PJM membership in general, (2) the basis for establishing limits that will be imposed on a Market Participant in order to minimize risk, and (3) various obligations and requirements the violation of which will result in an Event of Default pursuant to this Attachment Q and the Agreements.

Attachment Q describes the types of data and information PJM will review in order to determine whether an Applicant or Market Participant presents an unreasonable risk to any PJM Markets and/or PJM membership in general, and the steps PJM may take in order to address that risk.

APPLICABILITY

This Attachment Q applies to all Applicants and Market Participants who take Transmission Service under this Tariff, or participate in any PJM Markets or market activities under the Agreements. Notwithstanding anything to the contrary in this Attachment Q, simply taking transmission service or procuring Ancillary Services via market-based rates does not imply market participation for purposes of applicability of this Attachment Q.

II. RISK EVALUATION PROCESS

PJM will conduct a risk evaluation to determine eligibility to become and/or remain a Market Participant or Guarantor that: (1) assesses the entity's financial strength, risk profile, creditworthiness, and other relevant factors; (2) determines an Unsecured Credit Allowance, if appropriate; (3) determines appropriate levels of Collateral; and (4) evaluates any Credit Support, including Guaranties or Letters of Credit.

A. Initial Risk Evaluation

PJM will perform an initial risk evaluation of each Applicant and/or its Guarantor. As part of the initial risk evaluation, PJM will consider certain Minimum Participation Requirements, assign an Internal Risk Score, establish an Unsecured Credit Allowance if appropriate, and make a determination regarding required levels of Collateral, creditworthiness, credit support, Restricted Collateral and other assurances for participation in certain PJM Markets.

Each Applicant and/or its Guarantor must provide the information set forth below at the time of its initial application pursuant to this Attachment Q and on an ongoing basis in order to remain eligible to participate in any PJM Markets. The same quantitative and qualitative factors will be used to evaluate Participants whether or not they have rated debt.

1. Rating Agency Reports

PJM will review Rating Agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other Nationally Recognized Statistical Rating Organization for each Applicant and/or Guarantor. The review will focus on the Applicant's or its Guarantor's senior unsecured debt ratings. If senior unsecured debt ratings are not available, PJM may consider other ratings, including issuer ratings, corporate ratings and/or an implied rating based on an internally derived Internal Credit Score pursuant to section II.A.3 below.

2. Financial Statements and Related Information

Each Applicant and/or its Guarantor must submit, or cause to be submitted, audited financial statements, except as otherwise indicated below, prepared in accordance with United States Generally Accepted Accounting Principles ("US GAAP") or any other format acceptable to PJM for the three (3) fiscal years most recently ended, or the period of existence of the Applicant and/or its Guarantor, if shorter. Applicants and/or their Guarantors must submit, or cause to be submitted, financial statements, which may be unaudited, for each completed fiscal quarter of the current fiscal year. All audited financial statements provided by the Applicant and/or its Guarantor must be audited by an Independent Auditor.

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

(a) If the Applicant and/or its Guarantor has publicly traded securities:

(i) Annual reports on Form 10-K, together with any amendments thereto;

(ii) Quarterly reports on Form 10-Q, together with any amendments thereto;

(iii) Form 8-K reports, if any, that have been filed since the most recent Form 10-K;

(iv) A summary provided by the Principal responsible, or to be responsible, for PJM Market activity of: (1) the Participant's primary purpose(s) of activity or anticipated activity in the PJM Markets (investment, trading or "hedging or mitigating commercial risks," as such phrase has meaning in the CFTC's regulations regarding the end-user exception to clearing); (2) the experience of the Participant (and its Principals) in managing risks in similar markets, including other organized RTO/ISO markets or on regulated commodity exchanges; and (3) a high level overview of the Participant's intended participation in the PJM Markets.

(v) All audited financial statements provided by an Applicant with publicly traded securities and/or its Guarantor with publicly traded securities must be audited by an Independent Auditor that satisfies the requirements set forth in the Sarbanes-Oxley Act of 2002.

(b) If the Applicant and/or its Guarantor does not have publicly-traded securities:

(i) Annual Audited Financial Statements or equivalent independently audited financials, and quarterly financial statements, generally found on:
- Balance Sheets
- Income Statements
- Statements of Cash Flows
- Statements of Stockholder's or Member's Equity or Net Worth;

(ii) Notes to Annual Audited Financial Statements, and notes to quarterly financial statements if any, including disclosures of any material changes from the last report;

(iii) Disclosure equivalent to a Management's Discussion & Analysis, including an executive overview of operating results and outlook, and compliance with debt covenants and indentures, and off balance sheet arrangements, if any;

(iv) Auditor's Report with an unqualified opinion or written letter from auditor containing the opinion whether the annual audited financial statements comply with the US GAAP or any other format acceptable to PJM; and

(v) A summary provided by the Principal responsible or to be responsible for PJM Market activity of: (1) the Participant's primary purpose(s) of activity or anticipated activity in the PJM Markets (investment, trading or "hedging or mitigating commercial risks," as such phrase has meaning in the CFTC's regulations regarding the end-user exception to clearing); (2) the experience of the Participant (and its Principals) in managing risks in similar markets, including other organized RTO/ISO markets or on regulated commodity exchanges; and (3) a high level overview of the Participant's intended participation in the PJM Markets.

(c) If Applicant and/or Guarantor is newly formed, does not yet have three (3) years of audited financials, or does not routinely prepare audited financial statements, PJM may specify other information to allow it to assess the entity's creditworthiness, including but not limited to:

(i) Equivalent financial information traditionally found in:
- Balance Sheets
- Income Statements
- Statements of Cash Flows

(ii) Disclosure equivalent to a Management's Discussion & Analysis, including an executive overview of operating results and outlook, and compliance with debt covenants and indentures, and off balance sheet arrangements, if any; and

(iii) A summary provided by the Principal responsible or to be responsible for PJM Market activity of: (1) the Participant's primary purpose(s) of activity or anticipated activity in the PJM Markets (investment, trading or "hedging or mitigating commercial risks," as such phrase has meaning in the CFTC's regulations regarding the end-user exception to clearing); (2) the experience of the Participant (and its Principals) in managing risks in similar markets, including other organized RTO/ISO markets or on regulated commodity exchanges; and (3) a high level overview of the Participant's intended participation in the PJM Markets.

(d) During a two year transition period from June 1, 2020 to May 31, 2022, the Applicant or Guarantor may provide a combination of audited financial statements and/or equivalent financial information.

If any of the above information in this section II.A.2 is available on the internet, the Applicant and/or its Guarantor may provide a letter stating where such statements can be located and retrieved by PJM. If an Applicant and/or its Guarantor files Form 10-K, Form 10-Q, or Form 8-K with the SEC, then the Applicant and/or its Guarantor will be deemed to have satisfied the requirement by indicating to PJM where the information in this section II.A.2 can be located on the internet.

If the Applicant and/or its Guarantor fails, for any reason, to provide the information required above in this section II.A.2, PJM has the right to (1) request Collateral and/or Restricted Collateral to cover the amount of risk reasonably associated with the Applicant and/or its Guarantor's expected activity in any PJM Markets, and/or (2) restrict the Applicant from participating in certain PJM Markets, including but not limited to restricting the positions the Applicant (once it becomes a Market Participant) takes in the market.

For certain Applicants and/or their Guarantors, some of the above submittals may not be applicable and alternate requirements for compliant submittals may be specified by PJM. In the credit evaluation of Municipalities and Cooperatives, PJM may also request additional information as part of the initial and ongoing review process and will consider other qualitative factors in determining financial strength and creditworthiness.

3. Credit Rating and Internal Credit Score

PJM will use credit risk scoring methodologies as a tool in determining an Unsecured Credit Allowance for each Applicant and/or its Guarantor. As its source for calculating the Unsecured Credit Allowance, PJM will rely on the ratings from a Rating Agency, if any, on the Applicant's or Guarantor's senior unsecured debt or their issuer ratings or corporate ratings if senior unsecured debt ratings are not available. If there is a split rating between the Rating Agencies, the lower of the ratings shall apply. If no external credit rating is available PJM will utilize its Internal Credit Score in order to calculate the Unsecured Credit Allowance.

The model used to develop the Internal Credit Score will be quantitative, based on financial data found in the income statement, balance sheet, and cash flow statement, and it will be qualitative based on relevant factors that may be internal or external to a particular Applicant and/or its Guarantor.

PJM will employ a framework, as outlined in Tables 1-5 below, based on metrics internal to the Applicant and/or its Guarantor, including capital and leverage, cash flow coverage of fixed obligations, liquidity, profitability, and other qualitative factors. The particular metrics and scoring rules differ according to the Applicant's or Guarantor's line of business and the PJM Markets in which it anticipates participating, in order to account for varying sources and degrees of risk to the PJM Markets and PJM members.

The formulation of each metric will be consistently applied to all Applicants and Guarantors across industries with slight variations based on identifiable differences in entity type, anticipated market activity, and risks to the PJM Markets and PJM members. In instances where the external credit rating is used to calculate the unsecured credit allowance, PJM may also use the Internal Credit Score as an input into determining the overall risk profile of an Applicant and/or its Guarantor.

Table 1. ***Quantitative Metrics by Line of Business: Leverage and Capital Structure***	**Investor-Owned Utilities**	**Municipal Utilities**	**Co-Operative Utilities**	**Power Transmission**	**Merchant Power**	**Project Developers**	**Exploration & Production**	**Financial Institutions**	**Commodity Trading**	**Private Equity**
Debt / Total Capitalization (%)	primary	primary	primary	primary	secondary	secondary	primary		primary	primary
FFO / Debt (%)	secondary	secondary	primary	secondary	primary	primary	secondary		primary	
Debt / EBITDA (x)	secondary	secondary	secondary	secondary	primary	primary	secondary		primary	
Debt / Property, Plant & Equipment (%)	secondary	secondary	secondary	secondary						
Retained Earnings / Total Assets (%)	primary	primary		primary			primary			
Debt / Avg Daily Production or KwH ($)	secondary	secondary	secondary	secondary			primary			
Tangible Net Worth ($)						secondary		primary	secondary	secondary
Core Capital / Total Assets (%)								primary		
Risk-Based Capital / RWA (%)								primary		
Tier 1 Capital / RWA (%)								primary		
Equity / Investments (%)										primary
Debt / Investments (%)										primary

primary metric *secondary metric* *FFO = Funds From Operations* *RWA = Risk-Weighted Asserts*

Table 2. ***Quantitative Metrics by Line of Business: Fixed Charge Coverage and Funding***	**Investor-Owned**	**Municipal Utilities**	**Co-Operativ**	**Power Transmissi**	**Merchant Power**	**Project Developers**	**Exploration & Production**	**Financial Institutions**	**Commodity Trading**	**Private Equity**
EBIT / Interest Expense (x)	primary	primary	primary	primary	primary	primary	primary		primary	primary
EBITDA / Interest Expense (x)	primary	primary	secondary	primary	primary	primary	primary			
EBITDA / [Interest Exp + CPLTD] (x)	secondary	secondary	primary	secondary	secondary	secondary	secondary			
[FFO + Interest Exp] / Interest Exp (x)	secondary	secondary	primary	secondary	secondary	secondary	secondary			
Loans / Total Deposits (%)								primary		
NPL / Gross Loans (%)								primary		
NPL / [Net Worth + LLR] (%)								primary		
Market Funding / Tangible Bank Assets (%)								primary		

primary metric *secondary metric* *CPLTD = Current Portion of Long-Term Debt EBIT = Earnings Before Interest and Taxes EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization LLR = Loan Loss Reserves NPL = Non-Performing Loans*

Table 3. ***Quantitative Metrics by Line of Business: Liquidity***	Investor-Owned Utilities	Municipal Utilities	Co-Operative Utilities	Power Transmission	Merchant P	Project Developers	Exploration &	Financial Institutions	Commodity Trading	Private Equity
CFFO / Total Debt (x)	primary metric	primary metric		primary metric	primary metric	primary metric	primary metric		primary metric	
Current Assets / Current Liabilities (x)	primary metric	primary metric	primary metric	primary metric	primary metric	primary metric	primary metric		primary metric	
Liquid Assets / Tangible Bank Assets (%)								primary metric		
Sources / Uses of Funds (x)	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	primary metric
Weighted Avg Maturity of Debt (yrs)	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric
Floating Rate Debt / Total Debt (%)	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric

primary metric *secondary metric* *CFFO = Cash Flow From Operations*

Table 4. ***Quantitative Metrics by Line of Business: Profitability***	Investor-Owned Utilities	Municipal Utilities	Co-Operative Utilities	Power Transmission	Merchant P	Project Developers	Exploration &	Financial Institutions	Commodity Trading	Private Equity
Return on Assets (%)	primary metric	primary metric		primary metric	primary metric	primary metric	primary metric	primary metric		primary metric
Return on Equity (%)	primary metric	primary metric		primary metric	primary metric	primary metric	primary metric		primary metric	primary metric
Profit Volatility (%)	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	secondary metric	primary metric	primary metric	
Return on Revenue (%)					secondary metric	secondary metric	secondary metric	primary metric		primary metric
Net Income / Tangible Assets (%)								primary metric		
Net Profit ($)								primary metric		
Net Income / Dividends (x)								primary metric		

primary metric *secondary metric*

Table 5. Qualitative Factors: Industry Level	**Sample Reference Metrics**	**Investor-Owned Utilities**	**Municipal Utilities**	**Co-Operative Utilities**	**Power Transmission**	**Merchant Power**	**Project Developers**	**Exploration & Production**	**Financial Institutions**	**Commodity Trading**	**Private Equity**
Need for PJM Markets to Achieve Business Goals	Rating Agency criteria or other industry analysis	High	High	High	High	Med	Low	Med	Low	Low	N/A

Ability to Grow/Enter Markets other than PJM	Rating Agency criteria or other industry analysis	Very Low	Very Low	Very Low	Very Low	High	High	Med	Med	High	N/A
Other Participants' Ability to Serve Customers	Rating Agency criteria or other industry analysis	Low	Low	Low	Low	Low	Med	Low	Low	High	N/A
Regulation of Participant's Business	RRA regulatory climate scores, S&P BICRA	PUCS	Govt	N/A	FERC PUCs	N/A	N/A	N/A	N/A	N/A	N/A
Primary Purpose of PJM Activity	Investment ("Inv.")/ Trading ("Trade") / Hedging or Mitigating Commercial Risk of Operations ("CRH")	CRH	CRH	CRH	CRH / Trade	CRH / Trade	CRH / Trade	CRH/ Trade	Inv./ Trade	Inv./ Trade	Inv./ Trade

RRA = Regulatory Research Associates, a division of S&P Global, Inc. BICRA = Bank Industry Country Risk Assessment

The scores developed will range from 1-6, with the following mappings:

1 = Very Low Risk (S&P/Fitch: AAA to AA-; Moody's: Aaa to Aa3)
2 = Low Risk (S&P/Fitch: A+ to BBB+; Moody's: A1 to Baa1)
3 = Low to Medium Risk (S&P/Fitch: BBB; Moody's: Baa2)

4 = Medium Risk (S&P/Fitch: BBB-; Moody's: Baa3)
5 = Medium to High Risk (S&P/Fitch: BB+ to BB; Moody's Ba1 to Ba2)
6 = High Risk (S&P/Fitch: BB- and below; Moody's: Ba3 and below)

4. Trade References

If deemed necessary by PJM, whether because the Applicant is newly or recently formed or for any other reason, each Applicant and/or its Guarantor shall provide at least one (1) bank reference and three (3) Trade References to provide PJM with evidence of Applicant's understanding of the markets in which the Applicant is seeking to participate and the Applicant's experience and ability to manage risk. PJM may contact the bank references and Trade References provided by the Applicant to verify their business experience with the Applicant.

5. Litigation and Contingencies

Unless prohibited by law, each Applicant and Guarantor is also required to disclose and provide information as to the occurrence of, within the five (5) years prior to the submission of the information to PJM (i) any litigation, arbitration, investigation (formal inquiry initiated by a governmental or regulatory entity), or proceeding, pending or, to the knowledge of the involving, Applicant or its Guarantor or any of their Principals that would likely have a material adverse impact on its financial condition and/or would likely materially affect the risk of non-payment by the Applicant or Guarantor, or (ii) any finding of material defalcation, market manipulation or fraud by or involving the Applicant, Guarantor, or any of their Principals, predecessors, subsidiaries, or Credit Affiliates that participate in any United States power markets based upon a final adjudication of regulatory and/or legal proceedings, (iii) any bankruptcy declarations or petitions by or against an Applicant and/or Guarantor, or (iv) any violation by any of the foregoing of any federal or state regulations or laws regarding energy commodities, U.S. Commodity Futures Trading Commission ("CFTC") or FERC requirements, the rules of any exchange monitored by the National Futures Association, any self-regulatory organization or any other governing, regulatory, or standards body responsible for regulating activity in North American markets for electricity, natural gas or electricity-related commodity products. Each Applicant and Guarantor shall take reasonable measures to obtain permission to disclose information related to a non-public investigation. These disclosures shall be made by Applicant and Guarantor upon application, and within ten (10) Business Days of any material change with respect to any of the above matters.

6. History of Defaults in Energy Projects

Each Applicant and Guarantor shall disclose their current default status and default history for any energy related generation or transmission project (e.g. generation, solar, development), and within any wholesale or retail energy market, including but not limited to within PJM, any Independent System Operator or Regional Transmission Organization, and exchange that has not been cured within the past five (5) years. Defaults of a non-recourse project financed entity may not be included in the default history.

7. Other Disclosures and Additional Information

Each Applicant and Guarantor is required to disclose any Credit Affiliates that are currently Members of PJM, applying for membership with PJM, Transmission Customers, Participants, applying to become Market Participants, or that participate directly or indirectly in any PJM Markets or any other North American markets for electricity, natural gas or electricity-related commodity products. Each Applicant and Guarantor shall also provide a copy of its limited liability company agreement or equivalent agreement, certification of formation, articles of incorporation or other similar organization document, offering memo or equivalent, the names of its Principals, and information pertaining to any non-compliance with debt covenants and indentures.

Applicants shall provide PJM the credit application referenced in section III.A and any other information or documentation reasonably required for PJM to perform the initial risk evaluation of Applicant's or Guarantor's creditworthiness and ability to comply with the requirements contained in the Agreements related to settlements, billing, credit requirements, and other financial matters.

B. Supplemental Risk Evaluation Process

As described in section VI below, PJM will conduct a supplemental risk evaluation process for Applicants, Participants, and Guarantors applying to conduct virtual and export transactions or participate in any PJM Markets.

C. Unsecured Credit Allowance

A Market Participant may request that PJM consider it for an Unsecured Credit Allowance pursuant to the provisions herein. Notwithstanding the foregoing, an FTR Participant shall not be considered for an Unsecured Credit Allowance for participation in the FTR markets.

1. Unsecured Credit Allowance Evaluation

PJM will perform a credit evaluation on each Participant that has requested an Unsecured Credit Allowance, both initially and at least annually thereafter. PJM shall determine the amount of Unsecured Credit Allowance, if any, that can be provided to the Market Participant in accordance with the creditworthiness and other requirements set forth in this Attachment Q. In completing the credit evaluation, PJM will consider:

(a) Rating Agency Reports

PJM will review Rating Agency reports as for each Market Participant on the same basis as described in section II.A.1 above and section II.E.1 below.

(b) Financial Statements and Related Information

All financial statements and related information considered for an Unsecured Credit Allowance must satisfy all of the same requirements described in section II.A.2 above and section II.E.2 below.

2. Material Adverse Changes

Each Market Participant is responsible for informing PJM, in writing, of any Material Adverse Change in its financial condition (or the financial condition of its Guarantor) since the date of the Market Participant or Guarantor's most recent annual financial statements provided to PJM, pursuant to the requirements reflected in section II.A.2 above and section II.E.3 below.

In the event that PJM determines that a Material Adverse Change in the financial condition of a Market Participant warrants a requirement to provide Collateral, additional Collateral or Restricted Collateral, PJM shall comply with the process and requirements described in section II.A above and section II.E below.

3. Other Disclosures

Each Market Participant desiring an Unsecured Credit Allowance is required to make the disclosures and upon the same requirements reflected in section II.A.7 above and section II.E.7 below.

D. Determination of Unreasonable Credit Risk

Unreasonable credit risk shall be determined by the likelihood that an Applicant will default on a financial obligation arising from its participation in any PJM Markets. Indicators of potentially unreasonable credit risk include, but are not limited to, a history of market manipulation based upon a final adjudication of regulatory and/or legal proceedings, a history of financial defaults, a history of bankruptcy or insolvency within the past five (5) years, or a combination of current market and financial risk factors such as low capitalization, a reasonably likely future material financial liability, a low Internal Credit Score (derived pursuant to section II.A.3 above) and/or a low externally derived credit score. PJM's determination will be based on, but not limited to, information and material provided to PJM during its initial risk evaluation process, information and material provided to PJM in the Officer's Certification, and/or information gleaned by PJM from public and non-public sources.

If PJM determines that an Applicant poses an unreasonable credit risk to the PJM Markets, PJM may require Collateral, additional Collateral, or Restricted Collateral commensurate with the Applicant's risk of financial default, reject an application, and/or limit or deny Applicant's participation in the PJM Markets, to the extent and for the time period it determines is necessary to mitigate the unreasonable credit risk to the PJM Markets. PJM will reject an application if it determines that Collateral, additional Collateral, or Restricted Collateral cannot address the risk.

PJM will communicate its concerns regarding whether the Applicant presents an unreasonable credit risk, if any, in writing to the Applicant and attempt to better understand the circumstances surrounding that Applicant's financial and credit position before making its determination. In the event PJM determines that an Applicant presents an unreasonable credit risk that warrants a requirement to provide Collateral of any type, or some action to mitigate risk, PJM shall provide the Applicant with a written explanation of why such determination was made.

E. Ongoing Risk Evaluation

In addition to the initial risk evaluation set forth in sections II.A through II.D above and the annual certification requirements set forth in section III.A below, each Market Participant and/or its Guarantor has an ongoing obligation to provide PJM with the information required in section IV.A described in more detail below. PJM may also review public information regarding a Market Participant and/or its Guarantor as part of its ongoing risk evaluation. If appropriate, PJM will revise the Market Participant's Unsecured Credit Allowance and/or change its determination of creditworthiness, credit support, Restricted Collateral, required Collateral or other assurances pursuant to PJM's ongoing risk evaluation process.

Each Market Participant and/or its Guarantor must provide the information set forth below on an ongoing basis in order to remain eligible to participate in any PJM Markets. The same quantitative and qualitative factors will be used to evaluate Market Participants whether or not they have rated debt.

1. Rating Agency Reports

PJM will review Rating Agency reports for each Market Participant and/or Guarantor on the same basis as described in section II.A.1 above.

2. Financial Statements and Related Information

On an ongoing basis, Market Participants and/or their Guarantors shall provide the information they are required to provide as described in section II.A.2 above, pursuant to the schedule reflected below, with one exception. With regard to the summary that is required to be provided by the Principal responsible for PJM Market activity, with respect to experience of the Participant or its Principals in managing risks in similar markets, the Principal only needs to provide that information for a new Principal that was not serving in the position when the prior summary was provided. PJM will review financial statements and related information for each Market Participant and/or Guarantor on the same basis as described in section II.A.2 above.

Each Market Participant and/or its Guarantor must submit, or cause to be submitted, annual audited financial statements, except as otherwise indicated below, prepared in accordance with US GAAP or any other format acceptable to PJM for the fiscal year most recently ended within ten (10) calendar days of the financial statements becoming available and no later than one hundred twenty (120) calendar days after its fiscal year end. Market Participants and/or their Guarantors must submit, or cause to be submitted, financial statements, which may be unaudited, for each completed fiscal quarter of the current fiscal year, promptly upon their issuance, but no later than sixty (60) calendar days after the end of each fiscal quarter. All audited financial statements provided by the Market Participant and/or its Guarantor must be audited by an Independent Auditor.

Notwithstanding the foregoing, PJM may upon request, grant a Market Participant or Guarantor an extension of time, if the financials are not available within the time frame stated above.

3. Material Adverse Changes

Each Market Participant and each Guarantor is responsible for informing PJM, in writing, of any Material Adverse Change in its or its Guarantor's financial condition within five (5) Business Days of any Principal becoming aware of the occurrence of a Material Adverse Change since the date of the Market Participant or Guarantor's most recent annual financial statements provided to PJM. However, PJM may also independently establish from available information that a Participant and/or its Guarantor has experienced a Material Adverse Change in its financial condition without regard to whether such Market Participant or Guarantor has informed PJM of the same.

For the purposes of this Attachment Q, a Material Adverse Change in financial condition may include, but is not be limited to, any of the following:

(a) a bankruptcy filing;
(b) insolvency;
(c) a significant decrease in market capitalization;
(d) restatement of prior financial statements unless required due to regulatory changes;
(e) the resignation or removal of a Principal unless there is a new Principal appointed or expected to be appointed, a transition plan in place pending the appointment of a new Principal, or a planned restructuring of such roles;
(f) the filing of a lawsuit or initiation of an arbitration, investigation, or other proceeding that would likely have a material adverse effect on any current or future financial results or financial condition or increase the likelihood of non-payment;
(g) a material financial default in any other organized energy, ancillary service, financial transmission rights and/or capacity markets including but not limited to those of another Regional Transmission Organization or Independent System Operator, or on any commodity exchange, futures exchange or clearing house, that has not been cured or remedied after any required notice has been given and any cure period has elapsed;
(h) a revocation of a license or other authority by any Federal or State regulatory agency; where such license or authority is necessary or important to the Participant's continued business, for example, FERC market-based rate authority, or State license to serve retail load;
(i) a significant change in credit default swap spreads, market capitalization, or other market-based risk measurement criteria, such as a recent increase in Moody's KMV Expected Default Frequency (EDF^{tm}) that is materially greater than the increase in its peers' EDF^{tm} rates, or a collateral default swap (CDS) premium normally associated with an entity rated lower than investment grade;
(j) a confirmed, undisputed material financial default in a bilateral arrangement with another Participant or counterparty that has not been cured or remedied after any required notice has been given and any cure period has elapsed;

(k) the sale by a Participant of all or substantially all of its bilateral position(s) in the PJM Markets;
(l) any adverse changes in financial condition which, individually, or in the aggregate, are material; and,
(m) any adverse changes, events or occurrences which, individually or in the aggregate, could affect the ability of the entity to pay its debts as they become due or could reasonably be expected to have a material adverse effect on any current or future financial results or financial condition.

Upon identification of a Material Adverse Change, PJM shall evaluate the financial strength and risk profile of the Market Participant and/or its Guarantor at that time and may do so on a more frequent basis going forward. If the result of such evaluation identifies unreasonable credit risk to any PJM Market as further described in section II.E.8 below, PJM will take steps to mitigate the financial exposure to the PJM Markets. These steps include, but are not limited to requiring the Market Participant and/or each Guarantor to provide Collateral, additional Collateral or additional Restricted Collateral that is commensurate with the amount of risk in which the Market Participant wants to engage, and/or limiting the Market Participant's ability to participate in any PJM Market to the extent, and for the time-period necessary to mitigate the unreasonable credit risk. In the event PJM determines that a Material Adverse Change in the financial condition or risk profile of a Market Participant and/or Guarantor, warrants a requirement to provide Collateral of any type, or some action to mitigate risk, PJM shall provide the Market Participant and/or Guarantor, a written explanation of why such determination was made. Conversely, in the event PJM determines there has been an improvement in the financial condition or risk profile of a Market Participant and/or Guarantor such that the amount of Collateral needed for that Market Participant and/or Guarantor can be reduced, PJM shall provide a written explanation why such determination was made, including the amount of the Collateral reduction and indicating when and how the reduction will be made.

4. Litigation and Contingencies

Each Market Participant and/or Guarantor is required to disclose and provide information regarding litigation and contingencies as outlined in section II.A.5 above.

5. History of Defaults in Energy Projects

Each Market Participant and/or Guarantor is required to disclose current default status and default history as outlined in section II.A.6 above.

6. Internal Credit Score

As part of its ongoing risk evaluation, PJM will use credit risk scoring methodologies as a tool in determining an Internal Credit Score for each Market Participant and/or Guarantor, utilizing the same model and framework outlined in section II.A.3 above.

7. Other Disclosures and Additional Information

Each Market Participant and/or Guarantor is required to make other disclosures and provide additional information outlined in section II.A.7 above.

PJM will monitor each Market Participant's use of services and associated financial obligations on a regular basis to determine their total potential financial exposure and for credit monitoring purposes, and may require the Market Participant and/or Guarantor to provide additional information, pursuant to the terms and provisions described herein.

Market Participants shall provide PJM, upon request, any information or documentation reasonably required for PJM to monitor and evaluate a Market Participant's creditworthiness and compliance with the Agreements related to settlements, billing, credit requirements, and other financial matters.

8. Unreasonable Credit Risk

If PJM has reasonable grounds to believe that a Market Participant and/or its Guarantor poses an unreasonable credit risk to any PJM Markets, PJM may immediately notify the Market Participant of such unreasonable credit risk and (1) issue a Collateral Call to demand Collateral, additional Collateral, or Restricted Collateral or other assurances commensurate with the Market Participant's and/or its Guarantor's risk of financial default or other risk posed by the Market Participant's or Guarantor's financial condition or risk profile to the PJM Markets and PJM members, or (2) limit or suspend the Market Participant's participation in any PJM Markets, to the extent and for such time period PJM determines is necessary to mitigate the unreasonable credit risk to any PJM Markets. PJM will only limit or suspend a Market Participant's market participation if Collateral, additional Collateral or Restricted Collateral cannot address the unreasonable credit risk.

PJM's determination will be based on, but not limited to, information and material provided to PJM during its ongoing risk evaluation process or in the Officer's Certification, and/or information gleaned by PJM from public and non-public sources. PJM will communicate its concerns, if any, in writing to the Market Participant and attempt to better understand the circumstances surrounding the Market Participant's financial and credit position before making its determination. At PJM's request or upon its own initiative, the Market Participant or its Guarantor may provide supplemental information to PJM that would allow PJM to consider reducing the additional Collateral requested or reducing the severity of limitations or other restrictions designed to mitigate the Market Participant's credit risk. Such information shall include, but not be limited to: (i) the Market Participant's estimated exposure, (ii) explanations for any recent change in the Market Participant's market activity, (iii) any relevant new load or unit outage information; or (iv) any default or supply contract expiration, termination or suspension.

The Market Participant shall have five (5) Business Days to respond to PJM's request for supplemental information. If the requested information is provided in full to PJM's satisfaction during said period, the additional Collateral requirement shall reflect the Market Participant's anticipated exposure based on the information provided. Notwithstanding the foregoing, any additional Collateral requested by PJM in a Collateral Call must be provided by the Market Participant within the applicable cure period.

In the event PJM determines that an Market Participant and/or its Guarantor presents an unreasonable credit risk, as described above, that warrants a requirement to provide Collateral of any type, or some action to mitigate risk, PJM shall provide the Market Participant with a written explanation of why such final determination was made.

PJM has the right at any time to modify any Unsecured Credit Allowance and/or require additional Collateral as may be deemed reasonably necessary to support current or anticipated market activity as set forth in Tariff, Attachment Q, sections II.A.2 and II.C.1.b. Failure to remit the required amount of additional Collateral within the applicable cure period shall constitute an Event of Default.

F. Collateral and Credit Restrictions

PJM may establish certain restrictions on available credit by requiring that some amounts of credit, i.e. Restricted Collateral, may not be available to satisfy credit requirements. Such designations shall be construed to be applicable to the calculation of credit requirements only, and shall not restrict PJM's ability to apply such designated credit to any obligation(s) in case of a default. Any such Restricted Collateral will be held by PJM, as applicable. Such Restricted Collateral will not be returned to the Participant until PJM has determined that the risk for which such Restricted Collateral is being held has subsided or been resolved.

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

PJM will regularly post each Participant's and/or its Guarantor's credit requirements and credit provisions on the PJM web site in a secure, password-protected location. Each Participant and/or its Guarantor is responsible for monitoring such information, and maintaining sufficient credit to satisfy the credit requirements described herein. Failure to maintain credit sufficient to satisfy the credit requirements of the Attachment Q shall constitute a Credit Breach, and the Participant will be subject to the remedies established herein and in any of the Agreements.

G. Unsecured Credit Allowance Calculation

The external rating from a Rating Agency will be used as the source for calculating the Unsecured Credit Allowance, unless no external credit rating is available in which case PJM will utilize its Internal Credit Score for such purposes. If there is a split rating between the Rating Agencies, the lower of the ratings shall apply.

Where two or more entities, including Participants, are considered Credit Affiliates, Unsecured Credit Allowances will be established for each individual Participant, subject to an aggregate maximum amount for all Credit Affiliates as provided for in Attachment Q, section II.G.3.

In its credit evaluation of Municipalities and Cooperatives, PJM may request additional information as part of the ongoing risk evaluation process and will also consider qualitative factors in determining financial strength and creditworthiness.

1. Credit Rating and Internal Credit Score

As previously described in section II.A.3 above, PJM will determine the Internal Credit Score for an Applicant, Market Participant and/or its Guarantor using the credit risk scoring methodologies contained therein. Internal Credit Scores, ranging from 1-6, for each Applicant, Market Participant and/or its Guarantor, will be determined with the following mappings:

1 = Very Low Risk (S&P/Fitch: AAA to AA-; Moody's: Aaa to Aa3)
2 = Low Risk (S&P/Fitch: A+ to BBB+; Moody's: A1 to Baa1)
3 = Low to Medium Risk (S&P/Fitch: BBB; Moody's: Baa2)
4 = Medium Risk (S&P/Fitch: BBB-; Moody's: Baa3)
5 = Medium to High Risk (S&P/Fitch: BB+ to BB; Moody's Ba1 to Ba2)
6 = High Risk (S&P/Fitch: BB- and below; Moody's: Ba3 and below)

In instances where the external credit rating is used to calculate the unsecured credit allowance, PJM may also use the Internal Credit Score as an input into its determination of the overall risk profile of an Applicant and/or its Guarantor

2. Unsecured Credit Allowance

PJM will determine a Participant's Unsecured Credit Allowance based on its external rating or its Internal Credit Score, as applicable, and the parameters in the table below. The maximum Unsecured Credit Allowance is the lower of:

(a) A percentage of the Participant's Tangible Net Worth, as stated in the table below, with the percentage based on the Participant's external rating or Internal Credit Score, as applicable; and

(b) A dollar cap based on the external rating or Internal Credit Score, as applicable, as stated in the table below:

Internal Credit Score	Risk Ranking	Tangible Net Worth Factor	Maximum Unsecured Credit Allowance ($ Million)
1.00 – 1.99	1 – Very Low (AAA to AA-)	Up to 10.00%	$50
2.00 – 2.99	2 – Low (A+ to BBB+)	Up to 8.00%	$42

3.00 – 3.49	3 – Low to Medium (BBB)	Up to 6.00%	$33
3.50 – 4.49	4 – Medium (BBB-)	Up to 5.00%	$7
4.50 – 5.49	5 – Medium to High (BB+ to BB)	0%	$0
> 5.49	6 – High (BB- and below)	0%	$0

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

(a) The limit imposed in the Corporate Guaranty;

(b) The Unsecured Credit Allowance calculated for the Guarantor; and

(c) A portion of the Unsecured Credit Allowance calculated for the Guarantor in the case of Credit Affiliates.

PJM has the right at any time to modify any Unsecured Credit Allowance and/or require additional Collateral as may be deemed reasonably necessary to support current market activity. Failure to remit the required amount of additional Collateral within the applicable cure period shall be deemed an Event of Default.

PJM will maintain a posting of each Participant's Unsecured Credit Allowance, along with certain other credit related parameters, on the PJM website in a secure, password-protected location. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

3. Unsecured Credit Limits For Credit Affiliates

If two or more Participants are Credit Affiliates and have requested an Unsecured Credit Allowance, PJM will consider the overall creditworthiness of the Credit Affiliates when determining the Unsecured Credit Allowances in order not to establish more Unsecured Credit for the Credit Affiliates collectively than the overall corporate family could support.

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

PJM will work with the Credit Affiliates to allocate the total Unsecured Credit Allowance among the Credit Affiliates while assuring that no individual Participant, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. The aggregate Unsecured Credit for a Participant, including Unsecured Credit Allowance granted based on its own creditworthiness and risk profile, and any Unsecured Credit Allowance conveyed through a Guaranty shall not exceed $50 million. The aggregate Unsecured Credit for a Credit Affiliate~~s~~ corporate family shall not exceed $50 million. A Credit Affiliate corporate family subject to this cap shall request PJM to allocate the maximum Unsecured Credit amongst the corporate family, assuring that no individual Participant or common guarantor, shall exceed the Unsecured Credit level appropriate for its credit strength and activity.

H. Contesting an Unsecured Credit Evaluation

PJM will provide to a Participant, upon request, a written explanation for any determination of or change in Unsecured Credit or credit requirement within ten (10) Business Days of receiving such request.

If a Participant believes that either its level of Unsecured Credit or its credit requirement has been incorrectly determined, according to this Attachment Q, then the Participant may send a request for reconsideration in writing to PJM. Such a request should include:

(1) A citation to the applicable section(s) of this Attachment Q along with an explanation of how the respective provisions of this Attachment Q were not carried out in the determination as made; and

(2) A calculation of what the Participant believes should be the appropriate Unsecured Credit or Collateral requirement, according to terms of this Attachment Q.

PJM will provide a written response as promptly as practical, but no more than ten (10) Business Days after receipt of the request. If the Participant still feels that the determination is incorrect, then the Participant may contest that determination. Such contest should be in written form, addressed to PJM, and should contain:

(1) A complete copy of the Participant's earlier request for reconsideration, including citations and calculations;

(2) A copy of PJM's written response to its request for reconsideration; and

(3) An explanation of why it believes that the determination still does not comply with this Attachment Q.

PJM will investigate and will respond to the Participant with a final determination on the matter as promptly as practical, but no more than twenty (20) Business Days after receipt of the request.

Neither requesting reconsideration nor contesting the determination following such request shall relieve or delay Participant's responsibility to comply with all provisions of this Attachment Q, including without limitation posting Collateral, additional Collateral or Restricted Collateral in response to a Collateral Call.

If a Corporate Guaranty is being utilized to establish credit for a Participant, the Guarantor will be evaluated and the Unsecured Credit Allowance granted, if any, based on the financial strength and creditworthiness, and risk profile of the Guarantor. Any utilization of a Corporate Guaranty will only be applicable to non-FTR credit requirements, and will not be applicable to cover FTR credit requirements.

PJM will identify any necessary Collateral requirements and establish a Working Credit Limit for each Participant. Any Unsecured Credit Allowance will only be applicable to non-FTR credit requirements, for positions in PJM Markets other than the FTR market, because all FTR credit requirements must be satisfied by posting Collateral.

III. MINIMUM PARTICIPATION REQUIREMENTS

A Participant seeking to participate in any PJM Markets shall submit to PJM any information or documentation reasonably required for PJM to evaluate its experience and resources. If PJM determines, based on its review of the relevant information and after consultation with the Participant, that the Participant's participation in any PJM Markets presents an unreasonable credit risk, PJM may reject the Participant's application to become a Market Participant, notwithstanding applicant's ability to meet other minimum participation criteria, registration requirements and creditworthiness requirements.

A. Annual Certification

Before they are eligible to transact in any PJM Market, all Applicants shall provide to PJM (i) an executed copy of a credit application and (ii) a copy of the annual certification set forth in Attachment Q, Appendix 1. As a condition to continued eligibility to transact in any PJM Market, Market Participants shall provide to PJM the annual certification set forth in Attachment Q, Appendix 1.

After the initial submission, the annual certification must be submitted each calendar year by all Market Participants between January 1 and April 30. PJM will accept such certifications as a matter of course and the Market Participants will not need further notice from PJM before commencing or maintaining their eligibility to participate in any PJM Markets.

A Market Participant that fails to provide its annual certification by April 30 shall be ineligible to transact in any PJM Markets and PJM will disable the Market Participant's access to any PJM Markets until such time as PJM receives the certification. In addition, failure to provide an executed annual certification in a form acceptable to PJM and by the specified deadlines may result in a default under the Tariff.

Market Participants acknowledge and understand that the annual certification constitutes a representation upon which PJM will rely. Such representation is additionally made under the Tariff, filed with and accepted by FERC, and any false, misleading or incomplete statement knowingly made by the Market Participant and that is material to the Market Participant's ability to perform may be considered a violation of the Tariff and subject the Market Participant to action by FERC. Failure to comply with any of the criteria or requirements listed herein or in the certification may result in suspension or limitation of a Market Participant's transaction rights in any PJM Markets.

Applicants and Market Participants shall submit to PJM, upon request, any information or documentation reasonably and/or legally required to confirm Applicant's or Market Participant's compliance with the Agreements and the annual certification.

B. PJM Market Participation Eligibility Requirements

PJM may conduct periodic verification to confirm that Applicants and Market Participants can demonstrate that they meet the definition of "appropriate person" to further ensure minimum criteria are in place. Such demonstration will consist of the submission of evidence and an executed Annual Officer Certification form as set forth in Attachment Q, Appendix 1 in a form acceptable to PJM. If an Applicant or Market Participant does not provide sufficient evidence for verification to PJM within five (5) Business Days of written request, then such Applicant or Market Participant may result in a default under this Tariff. Demonstration of "appropriate person" status and support of other certifications on the annual certification is one part of the Minimum Participation Requirements for any PJM Markets and does not obviate the need to meet the other Minimum Participation Requirements such as those for minimum capitalization and risk profile as set forth in this Attachment Q.

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

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

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

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

4. an Applicant or Market Participant seeking eligibility as an "appropriate person" providing an unlimited Corporate Guaranty in a form acceptable to PJM as described in section V below from a Guarantor that has demonstrated it is an "appropriate person," and has at least $1 million of total net worth or $5 million of total assets per Applicant and Market Participant for which the Guarantor has issued an unlimited Corporate Guaranty, or;

5. an Applicant or Market Participant providing a Letter of Credit of at least $5 million to PJM in a form acceptable to PJM as described in section V below, that the Applicant or Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJM, or;

6. an Applicant or Market Participant providing a surety bond of at least $5 million to PJM in a form acceptable to PJM as described in section V below, that the Applicant or Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJM.

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

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

C. Risk Management and Verification

All Market Participants must maintain current written risk management policies, procedures, or controls to address how market and credit risk is managed, and are required to submit to PJM (at the time they make their annual certification) a copy of their current governing risk control policies, procedures and controls applicable to their market activities. PJM will review such documentation to verify that it appears generally to conform to prudent risk management practices for entities participating in any PJM Markets.

All Market Participants subject to this provision shall make a one-time payment of $1,500.00 to PJM to cover administrative costs. Thereafter, if such Participant's risk policies, procedures and controls applicable to its market activities change substantively, it shall submit such modified documentation, with applicable administrative charge determined by PJM, to PJM for review and verification at the time it makes its annual certification. All Market Participant's continued eligibility to participate in any PJM Markets is conditioned on PJM notifying a Participant that its annual certification, including the submission of its risk policies, procedures and controls, has been accepted by PJM. PJM may retain outside expertise to perform the review and verification function described in this section, however, in all circumstances, PJM and any third-party it may retain will treat as confidential the documentation provided by a Participant under this section, consistent with the applicable provisions of the Operating Agreement.

Participants must demonstrate that they have implemented prudent risk management policies and procedures in order to be eligible to participate in any PJM Markets. Participants must demonstrate on at least an annual basis that they have implemented and maintained prudent risk management policies and procedures in order to continue to participate in any PJM Markets. Upon written request, the Participant will have fourteen (14) calendar days to provide to PJM current governing risk management policies, procedures, or controls applicable to Participant's activities in any PJM Markets.

D. Capitalization

In advance of certification, Applicants shall meet the minimum capitalization requirements below. In addition to the annual certification requirements in Attachment Q, Appendix 1, a Market Participant shall satisfy the minimum capitalization requirements on an annual basis thereafter. A Participant must demonstrate that it meets the minimum financial requirements appropriate for the PJM Markets in which it transacts by satisfying either the minimum capitalization or the provision of Collateral requirements listed below:

1. Minimum Capitalization

Minimum capitalization may be met by demonstrating minimum levels of Tangible Net Worth or tangible assets. FTR Participants must demonstrate a Tangible Net Worth in excess of $1 million or tangible assets in excess of $10 million. Other Market Participants must demonstrate a Tangible Net Worth in excess of $500,000 or tangible assets in excess of $5 million.

(a) Consideration of tangible assets and Tangible Net Worth shall exclude assets which PJM reasonably believes to be restricted, highly risky, or potentially unavailable to settle a claim in the event of default. Examples include, but are not limited to, restricted assets, derivative assets, goodwill, and other intangible assets.

(b) Demonstration of "tangible" assets and Tangible Net Worth may be satisfied through presentation of an acceptable Corporate Guaranty, provided that both:

(i) the Guarantor is a Credit Affiliate company that satisfies the Tangible Net Worth or tangible assets requirements herein, and;

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

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

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

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

In the event that a Participant provides Collateral in addition to a limited Corporate Guaranty to increase its available credit, the value of such Collateral shall be reduced by 10%. This reduced value shall be considered the amount available to satisfy requirements of this Attachment Q.

(c) Demonstrations of minimum capitalization (minimum Tangible Net Worth or tangible assets) must be presented in the form of audited financial statements for the Participant's most recent fiscal year during the initial risk evaluation process and ongoing risk evaluation process.

2. Provision of Collateral

If a Participant does not demonstrate compliance with its applicable minimum capitalization requirements above, it may still qualify to participate in any PJM Markets by posting Collateral, additional Collateral, and/or Restricted Collateral, subject to the terms and conditions set forth herein.

Any Collateral provided by a Participant unable to satisfy the minimum capitalization requirements above will also be restricted in the following manner:

(a) Collateral provided by Market Participants that engage in FTR transactions shall be reduced by an amount of the current risk plus any future risk to any PJM Markets and PJM membership in general, and may coincide with limitations on market participation. The amount of this Restricted Collateral shall not be available to cover any credit requirements from market activity. The remaining value shall be considered the amount available to satisfy requirements of this Attachment Q.

(b) Collateral provided by other Participants that engage in Virtual Transactions or Export Transactions shall be reduced by $200,000 and then further reduced by 10%. The amount of this Restricted Collateral shall not be available to cover any credit requirements from market activity. The remaining value shall be considered the amount available to satisfy requirements of this Attachment Q.

(c) Collateral provided by other Participants that do not engage in Virtual Transactions or Export Transactions shall be reduced by 10%. The amount of this Restricted Collateral shall not be available to cover any credit requirements from market activity. The remaining value shall be considered the amount available to satisfy requirements of this Attachment Q.

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

(a) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this Attachment Q; or

(b) the face value of the Corporate Guaranty, reduced commensurate with the amount of the current risk plus any anticipated future risk to any PJM Markets and PJM membership in general, and may coincide with limitations on market participation.

IV. ONGOING COVENANTS

A. Ongoing Obligation to Provide Information to PJM

So long as a Participant is eligible to participate, or participates or holds positions, in any PJM Markets, it shall deliver to PJM, in form and detail satisfactory to PJM:

(1) All financial statements and other financial disclosures as required by section II.E.2 by the deadline set forth therein;

(2) Notice, within five (5) Business Days, of any Principal becoming aware that the Participant does not meet the Minimum Participation Requirements set forth in section III;

(3) Notice when any Principal becomes aware of any matter that has resulted or would reasonably be expected to result in a Material Adverse Change in the financial condition of the Participant or its Guarantor, if any, a description of such Material Adverse Change in detail reasonable to allow PJM to determine its potential effect on, or any change in, the Participant's risk profile as a participant in any PJM Markets, by the deadline set forth in section II.E.3 above;

(4) Notice, within the deadline set forth therein, of any Principal becoming aware of a litigation or contingency event described in section II.E.4, or of a Material Adverse Change in any such litigation or contingency event previously disclosed to PJM, information in detail reasonable to allow PJM to determine its potential effect on, or any change in, the Market Participant's risk profile as a participant in any PJM Markets by the deadline set forth therein;

(5) Notice, within two (2) Business Days after any Principal becomes aware of a Credit Breach, Financial Default, or Credit Support Default, that includes a description of such default or event and the Participant's proposals for addressing the default or event;

(6) As soon as available but not later than April 30th of any calendar year, the annual Certification described in section III.A in a form set forth in Attachment Q, Appendix 1;

(7) Concurrently with submission of the annual certification, demonstration that the Participant meets the minimum capitalization requirements set forth in section III.D;

(8) Concurrently with submission of the annual certification and within the applicable deadline of any substantive change, or within the applicable deadline of a request from PJM, a copy of the Participant's written risk management policies, procedures or controls addressing how the Participant manages market and credit risk in the PJM Markets in which it participates, as well as a high level summary by the chief risk officer or other Principal regarding any material violations, breaches, or compliance or disciplinary actions related to the risk management policies, by the Participant under the policies, procedures or controls within the prior 12 months, as set forth in section VI.B below;

(9) Within five (5) Business Days of request by PJM, evidence demonstrating the Participant meets the definition of "appropriate person" or "eligible contract participant," as those terms are defined in the Commodity Exchange Act and the CFTC regulations promulgated thereunder, or of any other certification in the annual Certification; or

(10) Within a reasonable time after PJM requests, any other information or documentation reasonably and/or legally required by PJM to confirm Participant's compliance with the Tariff and its eligibility to participate in any PJM Markets.

Participants acknowledge and understand that the deliveries constitute representations upon which PJM will rely in allowing the Participant to continue to participate in its markets, with the Internal Credit Score and Unsecured Credit Allowance, if any, previously determined by PJM.

B. Risk Management Review

PJM shall also conduct a periodic compliance verification process to review and verify, as applicable, Participants' risk management policies, practices, and procedures pertaining to the Participant's activities in any PJM Markets. PJM shall review such documentation to verify that it appears generally to conform to prudent risk management practices for entities trading in any PJM Markets. Participant shall also provide a high level summary by the chief risk officer or other Principal regarding any material violations, breaches, or compliance or disciplinary actions in connection with such risk management policies, practices and procedures within the prior twelve (12) months.

If a third-party industry association publishes or modifies principles or best practices relating to risk management in North American markets for electricity, natural gas or electricity-related commodity products, PJM may, following stakeholder discussion and with no less than six (6) months prior notice to stakeholders, consider such principles or best practices in evaluating the Participant's risk controls.

PJM will prioritize the verification of risk management policies based on a number of criteria, including but not limited to how long the entity has been in business, the Participant's and its Principals' history of participation in any PJM Markets, and any other information obtained in determining the risk profile of the Participant.

Each Participant's continued eligibility to participate in any PJM Markets is conditioned upon PJM notifying the Participant of successful completion of PJM's verification of the Participant's risk management policies, practices and procedures, as discussed herein. However, if PJM notifies the Participant in writing that it could not successfully complete the verification process, PJM shall allow such Participant fourteen (14) calendar days to provide sufficient evidence for verification prior to declaring the Participant as ineligible to continue to participate in any PJM Markets, which declaration shall be in writing with an explanation of why PJM could not complete the verification. If the Participant does not provide sufficient evidence for verification to PJM within the required cure period, such Participant will be considered in default under this Tariff. PJM may retain outside expertise to perform the review and verification function described in this paragraph. PJM and any third party it may retain will treat as confidential the documentation provided by a Participant under this paragraph, consistent with the applicable provisions of the Agreements. If PJM retains such outside expertise, a Participant may direct in writing that PJM perform the risk management review and verification for such Participant instead of utilizing a third party, provided however, that employees and contract employees of PJM shall not be considered to be such outside expertise or third parties.

Participants are solely responsible for the positions they take and the obligations they assume in any PJM Markets. PJM hereby disclaims any and all responsibility to any Participant or PJM

Member associated with Participant’s submitting or failure to submit its annual certification or PJM’s review and verification of a Participant’s risk policies, procedures and controls. Such review and verification is limited to demonstrating basic compliance by a Participant showing the existence of written policies, procedures and controls to limit its risk in any PJM Markets and does not constitute an endorsement of the efficacy of such policies, procedures or controls.

V. FORMS OF CREDIT SUPPORT

In order to satisfy their PJM credit requirements Participants may provide credit support in a PJM-approved form and amount pursuant to the guidelines herein, provided that, notwithstanding anything to the contrary in this section, a Market Participant in PJM’s FTR markets shall meet its credit support requirements related to those FTR markets with either cash or Letters of Credit.

Unless otherwise restricted by PJM, credit support provided may be used by PJM to secure the payment of Participant’s financial obligations under the Agreements.

Collateral which may no longer be required to be maintained under provisions of the Agreements, shall be returned at the request of a Participant, no later than two (2) Business Days following determination by PJM within a commercially reasonable period of time that such Collateral is not required.

Except when an Event of Default has occurred, a Participant may substitute an approved PJM form of Collateral for another PJM approved form of Collateral of equal value.

A. Cash Deposit

A Participant’s delivery of a cash deposit to PJM as Collateral shall constitute the grant of a first-priority security interest in the cash in favor of PJM and PJM shall be authorized by such delivery to hold the cash as security and to apply it to the Participant’s financial obligations under the Tariff or other Agreements. Cash provided by a Participant as Collateral will be held in a depository account by PJM. Interest on a cash deposit shall accrue to the benefit of the Participant, provided that PJM may require Participants to provide appropriate tax and other information in order to accrue such interest credits. A Participant who delivers cash to PJM hereunder agrees that the Tariff and any other agreements incorporating the terms of the Tariff shall for all purposes constitute a security agreement.

Cash Collateral may not be pledged or in any way encumbered or restricted from full and timely use by PJM in accordance with terms of the Agreements.

PJM has the right to liquidate all or a portion of the Collateral account balance at its discretion to satisfy a Participant’s Total Net Obligation to PJM in the Event of Default under this Attachment Q or one or more of the Agreements.

B. Letter of Credit

An unconditional, irrevocable standby Letter of Credit can be utilized to meet the Collateral requirement. As stated below, the form, substance, and provider of the Letter of Credit must all be acceptable to PJM.

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

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

(3) PJM will post on its web site an acceptable standard form of a Letter of Credit that should be utilized by a Participant choosing to submit a Letter of Credit to establish credit at PJM. If the Letter of Credit varies in any way from the standard format, it must first be reviewed and approved by PJM. All costs associated with obtaining and maintaining a Letter of Credit and meeting the Attachment Q provisions are the responsibility of the Participant.

(4) PJM may accept a Letter of Credit from a financial institution that does not meet the credit standards of this Attachment Q provided that the Letter of Credit has third-party support, in a form acceptable to PJM, from a financial institution that does meet the credit standards of this Attachment Q.

C. Corporate Guaranty

An irrevocable and unconditional Corporate Guaranty may be utilized to establish an Unsecured Credit Allowance for a Participant. Such credit will be considered a transfer of Unsecured Credit from the Guarantor to the Participant, and will not be considered a form of Collateral.

PJM will post on its web site an acceptable form that should be utilized by a Participant choosing to establish its credit with a Corporate Guaranty. If the Corporate Guaranty varies in any way from the PJM format, it must first be reviewed and approved by PJM before it may be applied to satisfy the Participant's credit requirements.
The Corporate Guaranty must be signed by an officer of the Guarantor, and must demonstrate that it is duly authorized in a manner acceptable to PJM. Such demonstration may include either a corporate seal on the Corporate Guaranty itself, or an accompanying executed and sealed secretary's certificate from the Guarantor's corporate secretary noting that the Guarantor was duly authorized to provide such Corporate Guaranty and that the person signing the Corporate Guaranty is duly authorized, or other manner acceptable to PJM.

PJM will evaluate the creditworthiness of a Guarantor and will establish any Unsecured Credit granted through a Corporate Guaranty using the methodology and requirements established for Participants requesting an Unsecured Credit Allowance as described herein. Foreign Guaranties and Canadian Guaranties shall be subject to additional requirements as established herein.
If PJM determines at any time that a Material Adverse Change in the financial condition of the Guarantor has occurred, or if the Corporate Guaranty comes within thirty (30) calendar days of expiring without renewal, PJM may reduce or eliminate any Unsecured Credit afforded to the Participant through the guaranty. Such reduction or elimination may require the Participant to provide Collateral within the applicable cure period. If the Participant fails to provide the required Collateral, the Participant shall be in default under this Attachment Q.

All costs associated with obtaining and maintaining a Corporate Guaranty and meeting the Attachment Q provisions are the responsibility of the Participant.

1. Foreign Guaranties

A Foreign Guaranty is a Corporate Guaranty that is provided by a Credit Affiliate entity that is domiciled in a country other than the United States or Canada. The entity providing a Foreign Guaranty on behalf of a Participant is a Foreign Guarantor. A Participant may provide a Foreign Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJM provided that all of the following conditions are met:

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

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

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

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

(b) A Foreign Guarantor:

(i) Must satisfy all provisions of this Attachment Q applicable to domestic Guarantors.

(ii) Must be a Credit Affiliate of the Participant.

(iii) Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.

(iv) Must be rated by at least one Rating Agency acceptable to PJM; the credit strength of a Foreign Guarantor may not be determined based on an evaluation of its audited financial statements without an actual credit rating as well.

(v) Must have a senior unsecured (or equivalent, in PJM's sole discretion) rating of BBB (one notch above BBB-) or greater by any and all agencies that provide rating coverage of the entity.

(vi) Must provide audited financial statements, in US GAAP format or any other format acceptable to PJM, with clear representation of net worth, intangible assets, and any other information PJM may require in order to determine the entity's Unsecured Credit Allowance.

(vii) Must provide a Secretary's Certificate from the Participant's corporate secretary certifying the adoption of Corporate Resolutions:

1. Authorizing and approving the Guaranty; and
2. Authorizing the Officers to execute and deliver the Guaranty on behalf of the Guarantor.

(viii) Must be domiciled in a country with a minimum long-term sovereign (or equivalent) rating of AA+/Aa1, with the following conditions:

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

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

(x) Must demonstrate financial commitment to activity in the United States as evidenced by one of the following:

1. American Depository Receipts (ADR) are traded on the New York Stock Exchange, American Stock Exchange, or NASDAQ.
2. Equity ownership worth over USD 100,000,000 in the wholly-owned or majority owned subsidiaries in the United States.

(xi) Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Attachment Q.

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

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

2. Canadian Guaranties

The entity providing a Canadian Guaranty on behalf of a Participant is a Canadian Guarantor. A Participant may provide a Canadian Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJM provided that all of the following conditions are met.

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

(a) A Canadian Guaranty:

(i) Must contain provisions equivalent to those contained in PJM's standard form of Foreign Guaranty with any modifications subject to review and approval by PJM counsel.

(ii) Must be denominated in US currency.

(iii) Must be written and executed solely in English, including any duplicate originals.

(b) A Canadian Guarantor:

(i) Must be a Credit Affiliate of the Participant.

(ii) Must satisfy all provisions of this Attachment Q applicable to domestic Guarantors.

(iii) Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.

(iv) Must be rated by at least one Rating Agency acceptable to PJM; the credit strength of a Canadian Guarantor may not be determined based on an evaluation of its audited financial statements without an actual credit rating as well.

(v) Must provide audited financial statements, in US GAAP format or any other format acceptable to PJM with clear representation of net worth, intangible assets, and any other information PJM may require in order to determine the entity's Unsecured Credit Allowance.

(vi) Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Attachment Q.

D. Surety Bond

An unconditional, irrevocable surety bond can be utilized to meet the Collateral requirement for Participants. As stated below, the form, substance, and provider of the surety bond must all be acceptable to PJM.

(i) An acceptable surety bond must be payable immediately upon demand without prior demonstration of the validity of the demand. The surety bond will only be accepted from a U.S. Treasury-listed approved surety that has either (i) a minimum corporate debt rating of "A" by Standard & Poor's or Fitch Ratings, or "A2" from Moody's Investors Service, or an equivalent short term rating from one of these agencies, or (ii) a minimum insurer rating of "A" by A.M. Best. PJMSettlement will consider the lowest applicable rating to be the rating of the surety. If the rating of a surety providing a surety bond is lowered below A/A2 by any rating agency, then PJMSettlement may require the Participant to provide a surety bond from another surety that is rated A/A2 or better, or to provide another form of Collateral.

(ii) The surety bond shall have an initial period of at least one year, and shall state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety (90) days prior written notice from the issuing surety. If PJM receives notice from the issuing surety that the current surety bond is being cancelled, the Participant will be required to provide evidence, acceptable to PJM, that such surety bond will be replaced with appropriate Collateral, effective as of the cancellation date of the surety bond, no later than thirty (30) days before the cancellation date of the surety bond, and no later than ninety (90) days after the notice of cancellation. Failure to do so will constitute a default under this Attachment Q and one of more of the Agreements enabling PJM to immediately demand payment of the full value of the surety bond.

(iii) PJM will post on its web site an acceptable standard form of a surety bond that should be utilized by a Participant choosing to submit a surety bond to establish credit at PJM. The acceptable standard form of surety bond will include non-negotiable provisions, including but not be limited to, a payment on demand feature, requirement that the bond be construed pursuant to Pennsylvania law, making the surety's obligation to pay out on the bond absolute and unconditional irrespective of the principal's (Market Participant's) bankruptcy, terms of any other agreements, investigation of the Market Participant by any entity or governmental authority, or PJM first attempting to collect payment from the Market Participant, and will require, among other things, that (a) the surety waive ***all*** rights that would be available to a principal or surety under the law, including but not limited to any right to investigate or verify any matter related to a demand for payment, rights to set-off amounts due by PJM to the Market Participant, and all counterclaims, (b) the surety expressly waive ***all*** of its and the principal's defenses, including illegality, fraud in the inducement, reliance on statements or representations of PJM and every other typically available defense; (c) the language of the bond that is determinative of the surety's obligation, and not the underlying agreement or arrangement between the principal and the oblige; (d) the bond shall not be conditioned on PJM first resorting to any other means of security or collateral, or pursuing any other remedies it may have; and (e) the surety acknowledge the continuing nature of its obligations in the event of termination or nonrenewal of the surety bond to make clear the surety remains liable for any obligations that arose before the effective date of its notice of cancellation of the surety bond. If the surety bond varies in any way from the standard format, it must first be reviewed and approved by PJM. PJM shall not accept any surety bond that varies in any material way from the standard format.

(iv) All costs associated with obtaining and maintaining a surety bond and meeting the Attachment Q provisions are the responsibility of the Participant.

(v) PJM shall not accept surety bonds with an aggregate value greater than $10 million dollars ($10,000,000) issued by any individual surety on behalf of any individual Participant.

(vi) PJM shall not accept surety bonds with an aggregate value greater than $50 million dollars ($50,000,000) issued by any individual surety.

E. PJM Administrative Charges

Collateral or credit support held by PJM shall also secure obligations to PJM for PJM administrative charges, and may be liquidated to satisfy all such obligations in an Event of Default.

F. Collateral and Credit Support Held by PJM

Collateral or credit support submitted by Participants and held by PJM shall be held by PJM for the benefit of PJM.

VI. SUPPLEMENTAL CREDIT REQUIREMENTS FOR SCREENED TRANSACTIONS

A. Virtual and Export Transaction Screening

1. Credit for Virtual and Export Transactions

Export Transactions and Virtual Transactions both utilize Credit Available for Virtual Transactions to support their credit requirements.

PJM does not require a Market Participant to establish separate or additional credit for submitting Virtual or Export Transactions; however, once transactions are submitted and accepted by PJM, PJM may require credit supporting those transactions to be held until the transactions are completed and their financial impact incorporated into the Market Participant's Obligations. If a Market Participant chooses to establish additional Collateral and/or Unsecured Credit Allowance in order to increase its Credit Available for Virtual Transactions, the Market Participant's Working Credit Limit for Virtual Transactions shall be increased in accordance with the definition thereof. The Collateral and/or Unsecured Credit Allowance available to increase a Market Participant's Credit Available for Virtual Transactions shall be the amount of Collateral and/or Unsecured Credit Allowance available after subtracting any credit required for Minimum Participation Requirements, FTR, RPM or other credit requirement determinants defined in this Attachment Q, as applicable.

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

A Market Participant may increase its Credit Available for Virtual Transactions by providing additional Collateral to PJM. PJM will make a good faith effort to make new Collateral available as Credit Available for Virtual Transactions as soon as practicable after confirmation of receipt. In any event, however, Collateral received and confirmed by noon on a Business Day will be applied (as provided under this Attachment Q) to Credit Available for Virtual Transactions no later than 10:00 am on the following Business Day. Receipt and acceptance of wired funds for cash deposit shall mean actual receipt by PJM's bank, deposit into PJM's customer deposit account, confirmation by PJM that such wire has been received and deposited, and entry into PJM's credit system. Receipt and acceptance of letters of credit or surety bonds shall mean receipt of the original Letter of Credit or surety bond, or amendment thereto, confirmation from PJM's credit and legal staffs that such Letter of Credit or surety bond, or amendment thereto conforms to PJM's requirements, which confirmation shall be made in a reasonable and practicable timeframe, and entry into PJM's credit system. To facilitate this process, bidders submitting additional Collateral for the purpose of increasing their Credit Available for Virtual Transactions are advised to submit such Collateral well in advance of the desired time, and to specifically notify PJM of such submission.

A Market Participant wishing to submit Virtual or Export Transactions must allocate within PJM's credit system the appropriate amount of Credit Available for Virtual Transactions to the virtual and export allocation sections within each customer account in which it wishes to submit such transactions.

2. Virtual Transaction Screening

All Virtual Transactions submitted to PJM shall be subject to a credit screen prior to acceptance in the Day-ahead Energy Market. The credit screen is applied separately for each of a Market

Participant’s customer accounts. The credit screen process will automatically reject Virtual Transactions submitted by the Market Participant in a customer account if the Market Participant’s Credit Available for Virtual Transactions, allocated on a customer account basis, is exceeded by the Virtual Credit Exposure that is calculated based on the Market Participant’s Virtual Transactions submitted, as described below.

A Market Participant’s Virtual Credit Exposure will be calculated separately for each customer account on a daily basis for all Virtual Transactions submitted by the Market Participant for the next Operating Day using the following equation:

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

(a) INC and DEC Exposure for each customer account is calculated as:

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

(b) Up-to Congestion Exposure for each customer account is calculated as:

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

3. Export Transaction Screening

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

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

B. RPM Auction and Price Responsive Demand Credit Requirements

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

Credit requirements described herein for RPM Auctions and RPM bilateral transactions are applied separately for each customer account of a Market Participant. Market Participants wishing to participate in an RPM Auction or enter into RPM bilateral transactions must designate the appropriate amount of credit to each account in which their offers are submitted.

1. Applicability

A Market Participant seeking to submit a Sell Offer in any RPM Auction based on any Capacity Resource for which there is a materially increased risk of nonperformance must satisfy the credit requirement specified herein before submitting such Sell Offer. A PRD Provider seeking to commit Price Responsive Demand for which there is a materially increased risk of non-performance must satisfy the credit requirement specified herein before it may commit the Price Responsive Demand. Credit must be maintained until such risk of non-performance is substantially eliminated, but may be reduced commensurate with the reduction in such risk, as set forth in section VI.B.3 below.

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

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

Except as provided for Credit-Limited Offers below, for any resource specified in section VI.B.1 above, other than Price Responsive Demand, the credit requirement shall be the RPM Auction Credit Rate, as provided in section VI.B.4 below, times the megawatts to be offered for sale from such resource in an RPM Auction. For Qualified Transmission Upgrades, the credit requirements shall be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit. The RPM Auction Credit Requirement for each Market Participant shall be determined on a customer account basis, separately for each customer account of a Market Participant, and shall be the sum of the credit requirements for all such resources to be offered by such Market Participant in the auction or, as applicable, cleared by such Market Participant in the relevant auctions. For Price Responsive Demand, the credit requirement shall be based on the Nominal PRD Value (stated in Unforced Capacity terms) times the Price Responsive Demand Credit Rate as set forth in section VI.B.5 below. Except for Credit-Limited Offers, the RPM Auction Credit requirement for a Market Participant will be reduced for any Delivery Year to the extent less than all of such Market Participant's offers clear in the Base Residual Auction or any Incremental Auction for such Delivery Year. Such reduction shall be proportional to the quantity, in megawatts, that failed to clear in such Delivery Year.

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Participant electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement, in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the Auction Credit Rate resulting from section VI.B.4.b. below; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Participant electing this alternative, the RPM Auction Credit requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-Limited Offer, and the RPM Auction Credit requirement subsequent to posting of the results will be the Auction Credit Rate, as provided in section VI.B.4.b, c. or d. of this Attachment Q, as applicable, times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The availability and operational details of Credit-Limited Offers shall be as described in the PJM Manuals.

As set forth in section VI.B.4 below, a Market Participant's Auction Credit requirement shall be determined separately for each Delivery Year.

3. Reduction in Credit Requirement

As specified below, the RPM Auction Credit Rate may be reduced under certain circumstances after the auction has closed.

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

In addition, the RPM Auction Credit requirement for a Market Participant for any given Delivery Year shall be reduced periodically, after the Market Participant has provided PJM a written request for each reduction, accompanied by documentation sufficient for PJM to verify attainment of required milestones or satisfaction of other requirements, and PJM has verified that the Market Participant has successfully met progress milestones for its Capacity Resource that reduce the risk of non-performance, as follows:

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

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

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

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

For externally financed projects, the Market Participant must submit with its request for reduction a sworn, notarized certification of a duly authorized independent engineer for the Financial Close, Full Notice to Proceed and Commencement of Construction, and Main Power Generating Equipment Delivered milestones.

For internally financed projects, the Market Participant must submit with its request for reduction a sworn, notarized certification of a duly authorized officer of the Market Participant for the Financial Close milestone and either a duly authorized independent engineer or Professional Engineer for the Full Notice to Proceed and Commencement of Construction and the Main Power Generating Equipment Delivered milestones.

The required certifications must be in a form acceptable to PJM, certifying that the engineer or officer, as applicable, has personal knowledge, or has engaged in a diligent inquiry to determine, that the milestone has been achieved and that, based on its review of the relevant project information, the engineer or officer, as applicable, is not aware of any information that could reasonably cause it to believe that the Capacity Resource will not be in-service by the beginning of the applicable Delivery Year. The Market Participant shall, if requested by PJM, supply to PJM on a confidential basis all records and documents relating to the engineer's and/or officer's certifications.

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

Credit Reduction Milestones for Planned External Generation Capacity Resources

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

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

(e) For Qualifying Transmission Upgrades, the RPM Auction Credit requirement shall be reduced to 50% of the amount calculated under section VI.B.2 above beginning as of the effective date of the latest associated Interconnection Service Agreement or Generation Interconnection Agreement (or, when a project will have no such agreement, an Upgrade Construction Service Agreement), and shall be reduced to zero on the date the Qualifying Transmission Upgrade is placed in service.

4. RPM Auction Credit Rate

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

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

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

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

(ii~~i~~) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season.

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

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

(i~~i~~) For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of calendar days in such Delivery Year).

(ii~~i~~) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season.

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

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

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

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

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

(i~~i~~) For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of calendar days in such Delivery Year); and

(i~~i~~i) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season.

(e) For the purposes of this section VI.B.4 and section VI.B.5 below, "Relevant LDA" means the Locational Deliverability Area in which the Capacity Performance Resource is located if a separate Variable Resource Requirement Curve has been established for that Locational Deliverability Area for the Base Residual Auction for such Delivery Year.

5. Price Responsive Demand Credit Rate

(a) For the 2018/2019 through 2022/2023 Delivery Years:

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

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

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

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

(b) For the 2022/2023 Delivery Year and Subsequent Delivery Years:

(i) Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (B) $20 per MW-day) times the number of calendar days in such Delivery Year;

(ii) Subsequent to the posting of the results from a Base Residual Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for Price Responsive Demand committed in such auction shall be (the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the Price Responsive Demand is located, in $/MW-day or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the Price Responsive Demand is located)] times the number of calendar days in such Delivery Year;

(iii) For any additional Price Responsive Demand that seeks to commit in a Third Incremental Auction in response to a qualifying change in the final LDA load forecast, the Price Responsive Demand Credit Rate shall be (the greater of (A) 0.5 times Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (B) $20/MW-day) times the number of calendar days in such Delivery Year; and

(iv) Subsequent to the posting of the results of the Third Incremental Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for all Price Responsive Demand committed in such auction shall be the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the Price Responsive Demand is located or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day minus (the Capacity Performance Resource Clearing Price in such Incremental Auction for the Locational Deliverability Areas within which the Price Responsive Demand is located)] times the number of calendar days in such Delivery Year.

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

In addition to the forms of credit specified elsewhere in this Attachment Q, RPM Seller Credit shall be available to Market Participants, but solely for purposes of satisfying RPM Auction Credit requirements. If a supplier has a history of being a net seller into PJM Markets, on average, over the past 12 months, then PJM will count as available Unsecured Credit twice the average of that Market Participant's total net monthly PJM bills over the past 12 months. This RPM Seller Credit shall be subject to the cap on available Unsecured Credit as established in section II.G.3 above.

RPM Seller Credit is calculated as a single value for each Market Participant, not separately by account, and must be designated to specific customer accounts in order to be available to satisfy RPM Auction Credit requirements that are calculated in each such customer account.

7. Credit Responsibility for Traded Planned RPM Capacity Resources

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

C. Financial Transmission Right Auctions

Credit requirements described herein for FTR activity are applied separately for each customer account of a Market Participant, unless specified otherwise in this section C. FTR Participants must designate the appropriate amount of credit to each separate customer account in which any activity occurs or will occur.

1. FTR Credit Limit.

Participants must maintain their FTR Credit Limit at a level equal to or greater than their FTR Credit Requirement for each applicable account. FTR Credit Limits will be established only by a Participant providing Collateral and designating the available credit to specific accounts.

2. FTR Credit Requirement.

For each Market Participant with FTR activity, PJM shall calculate an FTR Credit Requirement. The FTR Credit Requirement shall be calculated on a portfolio basis for each Market Participant based on (a) initial margin, (b) Auction Revenue Right Credits, (c) Mark-to-Auction Value, (d) application of a 10¢ per MWh minimum value adjustment, and (e) realized gains and/or losses, as set forth in subsections (a)-(e) of this subsection, employing the formula:

Max { Max (IM – ARR – MTA, Ten Cent per Mwh Minimum) – Realized Gains and/or Losses, 0}

Where IM is the initial margin, ARR is Auction Revenue Rights Credits and MTA is the Mark-to-Auction Value. The FTR Credit Requirement may be increased to reflect any change in the value of a Market Participant's portfolio requiring an increase in Collateral as further described below.

(a) Initial Margin

Initial margin shall be calculated in accordance with the following formula:

IM = FTR Obligations IM + FTR Options IM

The model will employ a confidence interval of 99 percent.

(i) FTR Obligations IM

Initial margin values for Financial Transmission Right Obligations shall be determined utilizing a historical simulation value-at-risk methodology that calculates the size and value at risk of the applicable FTR portfolio based on a defined confidence interval and subject to a weighted aggregation method that is represented by a straight sum for long term positions and a combination of straight sum (20%) and weighted root sum of squares (80%) for balance of planning period positions.

(ii) FTR Options IM

The initial margin for Financial Transmission Right Options shall be calculated as the FTR cost minus the FTR Historical Values. FTR Historical Values shall be calculated separately for weekend on-peak, weekday on-peak, off-peak, and 24-hour FTRs for each month of the year. FTR Historical Values shall be adjusted by plus or minus ten percent for cleared counter flow or prevailing flow FTRs, respectively, in order to mitigate exposure due to uncertainty and fluctuations in actual FTR value. Historical values used in the calculation of FTR Historical Values shall be adjusted when the network simulation model utilized in PJM's economic planning process indicates that transmission congestion will decrease due to certain transmission upgrades that are in effect or planned to go into effect for the following Planning Period. The transmission upgrades to be modeled for this purpose shall only include those upgrades that, individually, or together, have 10% or more impact on the transmission congestion on an individual constraint or constraints with congestion of $5 million or more affecting a common congestion path. The adjustments to historical values shall be the dollar amount of the adjustment shown in the network simulation model.

(b) Auction Revenue Rights Credits

For a given month for which initial margin is calculated, the prorated value of any Auction Revenue Rights Credits held by a Market Participant with Financial Transmission Right Obligations shall be subtracted from the initial margin for that month. In accordance with subsection 3 below, PJM may recalculate Auction Revenue Rights Credits at any time, but shall do so no less frequently than subsequent to each annual FTR auction. If a reduction in such ARR credits at any time increases an FTR Participant's FTR Credit Requirements beyond its credit available for FTR activity, the FTR Participant must increase its Collateral or the FTR Credit Limit.

(c) Mark-to-Auction Value

A Mark-to-Auction Value shall be calculated for each Market Participant in accordance with subsection 7 below.

(d) Ten Cent (10¢) per MWh Minimum Value Adjustment

If the FTR Credit Requirement as calculated pursuant to subsections (a)-(c) above, results in a value that is less than ten cents (10¢) per MWh, the FTR Credit Requirement shall be increased to ten cents (10¢) per MWh. When calculating the portfolio MWh for this comparison, for cleared "Sell" FTRs, the MWh shall be subtracted from the portfolio total; prior to clearing, the MWh for "Sell" FTRs shall not be included in the portfolio total.

(e) Realized Gains and/or Losses

Any realized gains and/or losses resulting from the settlement of Financial Transmission Right Obligations that have not been paid out will be subtracted from the FTR Credit Requirement. A realized gain will decrease the FTR Credit Requirement (but not below $0.00), whereas a realized loss will increase the FTR Credit Requirement.

3. Rejection of FTR Bids.

Bids submitted into an auction will be rejected if the Market Participant's FTR Credit Requirement including such submitted bids would exceed the Market Participant's FTR Credit Limit, or if the Market Participant fails to provide additional Collateral as required pursuant to provisions related to mark-to-auction.

4. FTR Credit Collateral Returns.

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

5. Credit Responsibility for Bilateral Transfers of FTRs.

PJM may require that credit responsibility associated with an FTR bilaterally transferred to a new Market Participant remain with the original party (which for these purposes, means the party bearing credit responsibility for the FTR immediately prior to bilateral transfer) unless and until the receiving party independently establishes, consistent with this Attachment Q, sufficient credit with PJM and agrees through confirmation of the bilateral transfer in PJM's FTR reporting tool that it will meet in full the credit requirements associated with the transferred FTR.

6. FTR Administrative Charge Credit Requirement

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

7. Mark-to-Auction

A Mark-to-Auction Value shall be calculated separately for each customer account of a Market Participant. For each such customer account, the Mark-to-Auction Value shall be a single number equal to the sum, over all months remaining in the applicable FTR period and for all cleared FTRs in the customer account, of the most recently available cleared auction price applicable to the FTR minus the original transaction price of the FTR, multiplied by the transacted quantity.

The FTR Credit Requirement, as otherwise described above, shall be increased when the Mark-to-Auction Value is negative and decreased when the Mark-to-Auction Value is positive. The increase shall equal the absolute value of the negative Mark-to-Auction Value less the value of ARR credits that are held in the customer account and have not been used to reduce the FTR Credit Requirement prior to application of the Mark-to-Auction Value. PJM shall recalculate ARR credits held by each Market Participant after each annual FTR auction and may also recalculate such ARR credits at any other additional time intervals it deems appropriate. Application of the Mark-to-Auction Value, including the effect from ARR application, shall not decrease the FTR Credit Requirement below the Ten Cent (10¢) per MWh Minimum.

For Market Participant customer accounts for which FTR bids have been submitted into the current FTR auction, if the Market Participant's FTR Credit Requirement exceeds its credit available for the Market Participant's portfolio of FTRs in the tentative cleared solution for an FTR auction (or auction round), PJM shall issue a Collateral Call to the Market Participant, and the Market Participant must fulfill such demand before 4:00 p.m. Eastern Prevailing Time on the following Business Day. If a Market Participant does not timely satisfy such Collateral Call, PJM shall, in coordination with PJM, cause the removal of all of that Market Participant's bids in that FTR auction (or auction round), submitted from such Market Participant's customer account, and a new cleared solution shall be calculated for the FTR auction (or auction round).

If necessary, PJM shall repeat the auction clearing calculation. PJM shall repeat these mark-to-auction calculations subsequent to any secondary clearing calculation, and PJM shall require affected Market Participants to establish additional credit.

Subsequent to final clearing of an FTR auction or an annual FTR auction round, PJM shall recalculate the FTR Credit Requirement for all FTR portfolios, and, as applicable, issue to each Market Participant a request for Collateral for the total amount by which the FTR Credit Requirement exceeds the credit allocated in any of the Market Participant's accounts. The Market Participant must fulfill such demand by 4:00 p.m. Eastern Prevailing Time on the following Business Day.

If the request for Collateral is not satisfied within the applicable cure period referenced in Operating Agreement, section 15, then such Market Participant shall be restricted in all of its credit-screened transactions. Specifically, such Market Participant may not engage in any Virtual Transactions or Export Transactions, or participate in RPM Auctions or other RPM activity. Such Market Participant may engage only in the selling of open FTR positions, either in FTR auctions or bilaterally, provided such sales would reduce the Market Participant's FTR Credit Requirements. PJM shall not return any Collateral to such Market Participant, and no payment shall be due or payable to such Market Participant, until its credit shortfall is remedied. Market Participant shall allocate any excess or unallocated Collateral to any of its account in which there is a credit shortfall. Market Participants may remedy their credit shortfall at any time through provision of sufficient Collateral.

If a Market Participant fails to satisfy a request for Collateral for two consecutive auctions of overlapping periods, e.g. two balance of Planning Period auctions, an annual FTR auction and a balance of Planning Period auction, or two long term FTR auctions, (for this purpose the four rounds of an annual FTR auction shall be considered a single auction), the Market Participant shall be declared in default of this Attachment Q.

VII. PEAK MARKET ACTIVITY AND WORKING CREDIT LIMIT

A. Peak Market Activity Credit Requirement

PJM shall calculate a Peak Market Activity credit requirement for each Participant. Each Participant must maintain sufficient Unsecured Credit Allowance and/or Collateral, as applicable, and subject to the provisions herein, to satisfy its Peak Market Activity credit requirement.

Peak Market Activity for Participants will be determined weekly, utilizing an initial Peak Market Activity, as explained in this section VII.A below. Peak Market Activity shall be the greater of the initial Peak Market Activity, or the greatest amount invoiced for the Participant's transaction activity for all PJM Markets and services in the rolling past one, two, three or four-week period.

However, Peak Market Activity shall not exceed the greatest amount invoiced for the Participant's transaction activity for all PJM Markets and services in any rolling one, two or three-week period in the prior 52 weeks.

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

Peak Market Activity = min [max [initial Peak Market Activity, max [greatest amount invoiced for transaction activity for the rolling past one, two, three, or four-week period]], max [greatest amount invoiced for transaction activity for any rolling one, two or three-week period in the prior 52 weeks]

When calculating Peak Market Activity, PJM may attribute credits for Regulation service to the days on which they were accrued, rather than including them in the month-end invoice.

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

The initial Peak Market Activity for Market Participants and Transmission Customers, calculated weekly upon issuance of the weekly invoice, shall be the three-week average of all non-zero invoice totals over the previous 52 weeks.

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

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

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

In the event that the Peak Market Activity Shortfall exceeds or equals the Minimum Exposure, the prior week's Peak Market Activity credit requirement will be increased by an amount equal to n * the Minimum Transfer Amount, with n being the integer that will cause the current week's Peak Market Activity credit requirement to be greater than or equal to the Participant's current Peak Market Activity but less than the Participant's current Peak Market Activity plus the Minimum Transfer Amount. For the avoidance of doubt, if the Peak Market Activity Shortfall is less than the Minimum Exposure, the current week's Peak Market Activity credit requirement will remain the same as the prior week's Peak Market Activity credit requirement.

In the event that the Peak Market Activity Surplus exceeds or equals the Minimum Transfer Amount, the prior week's Peak Market Activity credit requirement will be decreased by an amount equal to n * the Minimum Transfer Amount, with n being the integer that will cause the current week's Peak Market Activity credit requirement to be greater than or equal to the Participant's current Peak Market Activity but less than the Participant's current Peak Market Activity plus the Minimum Transfer Amount. For the avoidance of doubt, if the Peak Market Activity Surplus is less than the Minimum Transfer Amount, the current week's Peak Market Activity credit requirement will remain the same as the prior week's Peak Market Activity credit requirement.

In the event that there is neither a Peak Market Activity Shortfall nor a Peak Market Activity Surplus, then the current week's Peak Market Activity credit requirement is the same as the prior week's Peak Market Activity credit requirement.

PJM may, at its discretion, adjust a Participant's Peak Market Activity credit requirement if PJM determines that the Peak Market Activity is not representative of such Participant's expected activity, as a consequence of known, measurable, and sustained changes. Such changes may include, but shall not be limited to when a Participant makes PJM aware of federal, state or local law that could affect the allocation of charges or credits from a Participant to another party, the loss (without replacement) of short-term load contracts, when such contracts had terms of three months or more and were acquired through state-sponsored retail load programs, but shall not include short-term buying and selling activities.

PJM may waive the credit requirements for a Participant that has no outstanding transactions and agrees in writing that it shall not, after the date of such agreement, incur obligations under any of the Agreements. Such entity's access to all electronic transaction systems administered by PJM shall be terminated.

A Participant receiving unsecured credit may make early payments up to thirteen (13) times in a rolling 52-week period in order to reduce its Peak Market Activity for credit requirement purposes. Imputed Peak Market Activity reductions for credit purposes will be applied to the billing period for which the payment was received. Payments used as the basis for such reductions must be received prior to issuance or posting of the invoice for the relevant billing period. The imputed Peak Market Activity reduction attributed to any payment may not exceed the amount of Unsecured Credit for which the Participant is eligible.

B. Working Credit Limit

PJM will establish a Working Credit Limit for each Participant against which its Total Net Obligation will be monitored.

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

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

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

When calculating Total Net Obligation, PJM may attribute credits for Regulation service to the days on which they were accrued, rather than including them in the month-end invoice.

VIII. SUSPENSION OR LIMITATION ON MARKET PARTICIPATION

If PJM determines that a Participant presents an unreasonable credit risk as determined pursuant to initial or ongoing risk evaluations, as described in section II above, or in the case of any other event which, after notice, lapse of time, or both, would result in an Event of Default, PJM will take steps to mitigate the exposure of any PJM Markets, which may include, but is not limited to, requiring Collateral, additional Collateral or Restricted Collateral or suspending or limiting the Market Participant's ability to participate in the PJM Markets commensurate to the risk to any PJM Markets.

If a Participant fails to reduce or eliminate any unreasonable credit risks to PJM's satisfaction within the applicable cure period including without limitation by posting Collateral, additional Collateral or Restricted Collateral, PJM may treat such failure as an Event of Default.

Notwithstanding the foregoing, a Participant that transacts in FTRs will be eligible to request that PJM exempt or exclude FTR transactions of such Participant from the effect of any such limitations on market activity established by PJM, and PJM may but shall not be required to so exempt or exclude, any FTR transactions that the Participant reasonably demonstrates to PJM it has entered into to "hedge or mitigate commercial risk" arising from its transactions in the PJM Interchange Energy Market that are intended to result in the actual flow of physical energy or ancillary services in the PJM Region, as the phrase "hedge or mitigate commercial risks" is defined under the CFTC's regulations defining the end-user exception to clearing set forth in 17 C.F.R. §50.50(c).

IX. REMEDIES FOR CREDIT BREACH, FINANCIAL DEFAULT OR CREDIT SUPPORT DEFAULT; REMEDIES FOR EVENTS OF DEFAULT; GENERAL BANKRUPTCY PROVISIONS

If PJM determines that a Market Participant is in Credit Breach, or that a Financial Default or Credit Support Default exists, PJM may issue to the Market Participant a breach notice and/or a Collateral Call or demand for additional documentation or assurances. At such time, PJM may also suspend payments of any amounts due to the Participant and limit, restrict or rescind the Market Participant's privileges to participate in any or all PJM Markets under the Agreements during any such cure period. Failure to remedy the Credit Breach, Financial Default or to satisfy a Collateral Call or demand for additional documentation or assurances within the applicable cure period described in Operating Agreement, section 15.1.5, shall constitute an Event of

Default. If a Participant fails to meet the requirements of this Attachment Q, but then remedies the Credit Breach, Financial Default or Credit Support Default, or satisfies a Collateral Call or demand for additional documentation or assurances within the applicable cure period, then the Participant shall be deemed to again be in compliance with this Attachment Q, so long as no other Credit Breach, Financial Default, Credit Support Default or Collateral Call or demand for additional documentation or assurances has occurred and is continuing.

Only one cure period shall apply to a single event giving rise to a Credit Breach, Financial Default or Credit Support Default. Application of Collateral towards a Financial Default, Credit Breach or Credit Support Breach shall not be considered a cure of such Credit Breach, Financial Default or Credit Support Default unless the Participant is determined by PJM to be in full compliance with all requirements of this Attachment Q after such application.

When an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing, PJM may take such actions as may be required or permitted under the Agreements to protect the PJM Markets and the PJM Members, including but not limited to (a) suspension and/or termination of the Participant's ongoing Transmission Service, (b) limitation, suspension and/or termination of participation in any PJM Markets, (c) taking all necessary steps to address the Market Participant's market portfolio in accordance with the provisions of the Operating Agreement and PJM Tariff, including, but not limited to, allowing such portfolio's positions to go to settlement, liquidating or otherwise resolving such portfolio positions, exercising judgment in the manner in which this is achieved in any PJM Markets. PJM may permit a defaulting Market Participant to continue to participate in PJM Markets: (a) in support of grid reliability, (b) when such Market Participant is a net market seller, (c) when such Market Participant has the ability to post collateral, or (d) to enable certain customers to continue to receive service prior to PJM receiving regulatory or legal approval to terminate.

When an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing, PJM also has the immediate right to liquidate all or a portion of a Participant's Collateral at its discretion to satisfy Total Net Obligations to PJM under this Attachment Q or one or more of the Agreements. No remedy for an Event of Default is or shall be deemed to be exclusive of any other available remedy or remedies by contract or under applicable laws and regulations. Each such remedy shall be distinct, separate and cumulative, shall not be deemed inconsistent with or in exclusion of any other available remedy, and shall be in addition to and separate and distinct from every other remedy.

When an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing, PJM may continue to retain all payments due to a Participant as a cash security for all such Participant's obligations under the Agreements (regardless of any restrictions placed on such Participant's use of Collateral for any account, market activity or capitalization purpose); provided, however, that an Event of Default will not be deemed cured or no longer continuing because PJM is retaining amounts due the Participant, or because PJM has not yet applied Collateral or credit support to any amounts due PJM, unless PJM determines that the Participant has again satisfied all the Collateral requirements and application requirements as a new Applicant for participation in the PJM Markets, and consistent with the requirements and limitations of Operating Agreement, section 15.

In Event of Default by a Participant, PJM may exercise any remedy or action allowed or prescribed by this Attachment Q immediately or following investigation and determination of an orderly exercise of such remedy or action. Delay in exercising any allowed remedy or action shall not preclude PJM from exercising such remedy or action at a later time.

PJM may hold a defaulting Participant's Collateral for as long as such party's positions exist and consistent with this Attachment Q, in order to protect the PJM Markets and PJM's membership, and minimize or mitigate the impacts or potential impacts or risks associated with such Event of Default when an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing.

PJM may apply towards an ongoing Event of Default any amounts that are held or later become available or due to the defaulting Participant through PJM's markets and systems.

In order to cover the Participant's Obligations, PJM may hold a Participant's Collateral indefinitely and specifically through the end of the billing period which includes the 90th day following the last day a Participant had activity, open positions, or accruing obligations (other than reconciliations and true-ups), until such Participant has satisfactorily paid any obligations invoiced through such period and until PJM determines that the Participant's positions represent no risk exposure to the PJM Markets or the PJM Members. Obligations incurred or accrued through such period shall survive any withdrawal from PJM. When an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing, PJM may apply any Collateral to such Participant's Obligations, even if Participant had previously announced and effected its withdrawal from PJM.

To protect PJM Members and PJM Markets from loss and harm due to uncertainty and delay which may be created upon a Participant's bankruptcy, in the event a Participant becomes a debtor under the United States Bankruptcy Code, 11 U.S.C. §§ 101-1532 (the "Bankruptcy Code"), whether voluntarily or involuntarily, the Participant should upon the commencement of the bankruptcy case immediately seek through a "first day" motion or motions, to the extent appropriate under the circumstances to provide PJM with prompt clarity as to its rights and treatment, the entry of an order of the bankruptcy court: (i) authorizing and directing the Participant to (a) make prompt and full payment of all pre-petition Obligations to PJM; and (b) fulfill all obligations under the Tariff and other Agreements in the ordinary course of business, including but not limited to deposit of additional Collateral post-petition; (ii) authorizing PJM to (x) require, hold and apply Collateral in accordance with this Attachment Q and (y) exercise setoff and recoupment to the fullest extent provided under the Tariff and other Agreements, and applicable nonbankruptcy law; and (iii) confirming the status of Agreements as a "forward contract", "swap agreement", or "master netting agreement" under the Bankruptcy Code, as applicable.

In the event that a debtor Participant fails to file such a "first day" motion within one (1) Business Day of the commencement of the bankruptcy case, or the bankruptcy court does not enter an order granting the relief requested in such "first day" motion within seven (7) days thereof, PJM may file a motion for relief from the automatic stay under section 362(d) of the

Bankruptcy Code, citing the lack of prompt clarity as "cause" thereunder, to the extent necessary to permit PJM to exercise any rights and remedies under the Tariff and other Agreements.

X. FTR TRANSACTIONS AS FORWARD CONTRACTS AND/OR SWAP AGREEMENTS UNDER THE BANKRUPTCY CODE

Under the terms of the Tariff, PJM Settlement is the counterparty to all transactions in PJM Markets, including but not limited to all FTR transactions, other than (i) any bilateral transactions between Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection. Pursuant to the "Final Order in Response to a Petition From Certain Independent System Operators and Regional Transmission Organizations To Exempt Specified Transactions Authorized by a Tariff or Protocol Approved by the Federal Energy Regulatory Commission or the Public Utility Commission of Texas From Certain Provisions of the Commodity Exchange Act Pursuant to the Authority Provided in the Act" 78 Fed. Reg. 19880 (April 2, 2013) (the "CFTC RTO/ISO Order"), the Commodity Futures Trading Commission (the "CFTC") exempts transactions offered or entered into in a market administered by PJM pursuant to the Tariff, including but not limited to FTR transactions, from the provisions of the Commodity Exchange Act and the CFTC's rules applicable to "swaps," with the exception of the CFTC's general anti-fraud and anti-manipulation authority and scienter-based prohibitions.

Notwithstanding the CFTC RTO/ISO Order, all FTR transactions constitute "forward contracts" and/or "swap agreements" within the meaning of the Bankruptcy Code, and PJM shall be deemed to be a "forward contract merchant" and/or a "swap participant" within the meaning of the Bankruptcy Code for purposes of FTR transactions.

Pursuant to this Attachment Q and other provisions of the Agreements, PJM already has, and shall continue to have, the following rights (among other rights) with respect to a Market Participant's Event of Default under those documents: (a) the right to terminate, liquidate or otherwise resolve any FTR transaction or position held by that Market Participant, including by allowing such position to go to settlement; (b) the right to immediately proceed against any Collateral and additional financial assurance provided by that Market Participant; (c) the right to set off or recoup any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement, or similar agreement against any amounts due and owing by that Market Participant pursuant to any forward contract, swap agreement, or similar agreement, such arrangement to constitute a "master netting agreement" within the meaning of the Bankruptcy Code; and (d) the right to suspend or limit that Market Participant from entering into further FTR transactions.

For the avoidance of doubt, upon the commencement of a voluntary or involuntary proceeding for a Market Participant under the Bankruptcy Code, and without limiting any other rights of PJM or obligations of any Market Participant under the Tariff (including this Attachment Q) or other Agreements, PJM may exercise any of its rights against such Market Participant, including, without limitation (1) the right to terminate, liquidate or otherwise resolve any FTR transaction or position held by that Market Participant, including by allowing such position to go to settlement, (2) the right to immediately proceed against any Collateral and additional financial assurance provided by that Market Participant, (3) the right to set off or recoup any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement and/or master netting agreement against any amounts due and owing by that Market Participant with respect to an FTR transaction including as a result of the actions taken by PJM pursuant to (1) above, and (4) the right to suspend or limit that Market Participant from entering into future FTR transactions.

For purposes of the Bankruptcy Code, all transactions, including but not limited to FTR transactions, between PJM, on the one hand, and a Market Participant, on the other hand, are intended to be, and are, part of a single integrated agreement, and together with the Agreements constitute a "master netting agreement."

Attachment Q
Appendix 1

PJM MINIMUM PARTICIPATION CRITERIA

ANNUAL OFFICER CERTIFICATION FORM

Participant Name: ____ ("Participant")

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

1. All employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Amended and Restated Operating Agreement ("PJM Operating Agreement") on behalf of the Participant have received appropriate training and are authorized to transact on behalf of Participant. As used in this representation, the term "appropriate" as used with respect to training means training that is (i) comparable to generally accepted practices in the energy trading industry, and (ii) commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the participant._________

2. Participant has written risk management policies, procedures, and controls, approved by Participant's independent risk management function and applicable to transactions in any PJM Markets in which it participates and for which employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Operating Agreement have been trained, that provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Participant is exposed, including, but not limited to credit risks, liquidity risks and market risks. As used in this representation, a Participant's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Participant's trading functions, such as a risk management committee, a risk officer, a Participant's board or board committee, or a board or committee of the Participant's parent company.

    a. Participant is providing to PJM or PJMSettlement, in accordance with Tariff, Attachment Q, section III, with this Annual Officer Certification Form, a copy of its current governing risk management policies, procedures and controls applicable to its activities in any PJM Markets pursuant to Attachment Q or because there have been substantive changes made to such policies, procedures and controls applicable to its market activities since they were last provided to PJM.__________

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

3. An FTR Participant must make either the following 3.a. or 3.b. additional representations, evidenced by the undersigned officer initialing either the one 3.a. representation or the four 3.b. representations in the spaces provided below:

    a. Participant transacts in PJM's FTR markets with the sole intent to hedge congestion risk in connection with either obligations Participant has to serve load or rights Participant has to generate electricity in the PJM Region ("physical transactions") and monitors all of the Participant's FTR market activity to endeavor to ensure that its FTR positions, considering both the size and pathways of the positions, are either generally proportionate to or generally do not exceed the Participant's physical transactions, and remain generally consistent with the Participant's intention to hedge its physical transactions.__________

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

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

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

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

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

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

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

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

      If providing audited financial statements, which shall be in US GAAP format or any other format acceptable to PJM, to support Participant's certification of qualification as an "appropriate person:"

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

      If not providing audited financial statements to support Participant's certification of qualification as an "appropriate person," Participant certifies that they qualify as an "appropriate person" under one of the entities defined in section 4(c)(3)(A)-(J) of the Commodities Exchange Act. __________

      If providing audited financial statements, which shall be in US GAAP format or any other format acceptable to PJM, to support Participant's certification of qualification as an "eligible contract participant:"

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

         If not providing audited financial statements to support Participant's certification of qualification as an "eligible contract participant," Participant certifies that they qualify as an "eligible contract participant" under one of the entities defined in section 1a(18)(A) of the Commodities Exchange Act. __________

b. I certify that Participant has provided an unlimited Corporate Guaranty in a form acceptable to PJM as described in Tariff, Attachment Q, section III.D from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty. I also certify, to the best of my knowledge and belief, that the audited financial statements provided to PJM and/or PJMSettlement present fairly, pursuant to such disclosures in such audited financial statements, the financial position of the issuer as of the date of those audited financial statements. Further, I certify that Participant will cease transacting PJM's Markets and notify PJM and PJMSettlement immediately if issuer of the unlimited Corporate Guaranty for Participant no longer has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty.__________

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

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

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

   2. Transmitting electric energy:__________

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

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

      Description only if c(4) is initialed:

      ____

   Further, I certify that Participant will cease transacting in any PJM Markets and notify PJM and PJMSettlement immediately if Participant no longer performs at least one of the functions noted above in the PJM Region. I acknowledge that PJM and

PJMSettlement are relying on my certification to maintain compliance with federal energy regulatory requirements.__________

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

e. I certify that Participant has provided a surety bond of $5 million or more to PJM or PJMSettlement in a form acceptable to PJM and/or PJMSettlement as described in Tariff, Attachment Q, section V.D. that the Participant acknowledges cannot be utilized to meet its credit requirements to PJM and PJMSettlement. I acknowledge that PJM and PJMSettlement are relying on the provision of this surety bond and my certification to maintain compliance with federal regulatory requirements. __________

7. I acknowledge that I have read and understood the provisions of Tariff, Attachment Q applicable to Participant's business in any PJM Markets, including those provisions describing PJM's Minimum Participation Requirements and the enforcement actions available to PJM and PJMSettlement of a Participant not satisfying those requirements. I acknowledge that the information provided herein is true and accurate to the best of my belief and knowledge after due investigation. In addition, by signing this certification, I acknowledge the potential consequences of making incomplete or false statements in this Certification.__________

Date: ____________________________ ________________________________

Participant (Signature)

Print Name: ________________________________

Title: ________________________________

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) ~~Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017;~~

~~d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for the 2017/2018 Delivery Year;~~

~~e) Determining Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints for the 2018/2019 and 2019/2020 Delivery Years;~~

~~f)~~ Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction;

~~g~~d) Calculating the EFORd for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction;

~~h~~e) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

~~i~~f) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

~~j~~g) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

~~k~~h) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with Operating Agreement, section 18.17, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Tariff, Attachment DD.

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the minimum offer price rule set forth in Tariff, Attachment DD, ~~section 5.14(h) and Tariff, Attachment DD,~~ section 5.14~~(h-1)~~ (h-2). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Tariff, Attachment DD, section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.5A Capacity Resource Types

(a) Capacity Performance Resources

Capacity Performance Resources are Capacity Resources which, to the extent such resources cleared in a Reliability Pricing Model Auction or are otherwise committed as a Capacity Resource, are obligated to deliver energy during the relevant Delivery Year as scheduled and/or dispatched by the Office of Interconnection during the Performance Assessment Intervals. As further detailed in Tariff, Attachment DD, section 10A, Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d). Subject to 5.5A(a)(i), the following types of Capacity Resources are eligible to submit a Sell Offer as a Capacity Performance Resource: internal or external Generation Capacity Resources; Annual Demand Resources; Capacity Storage Resources; Annual Energy Efficiency Resources; and Qualifying Transmission Upgrades. To the extent the underlying Capacity Resource is an external Generation Capacity Resource, such resource must meet, to the extent subsection (b) or (c) of this section is applicable to offers from such resource, meet the applicable requirements of such subsection, and if neither subsection (b) or (c) is applicable, then offers from such resource must the criteria for obtaining an exception to the Capacity Import Limit as contained in RAA, Article 1.

(i) Process for Support and Review of Capacity Performance Resource Offers

A. The Capacity Market Seller shall provide to the Office of the Interconnection and the Market Monitoring Unit, upon their request, all supporting data and information requested by either the Office of the Interconnection or the Market Monitoring Unit to evaluate whether the underlying Capacity Resource can meet the operational and performance requirements of Capacity Performance Resources. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes.

B. The Office of the Interconnection and the Market Monitoring Unit shall review any requested supporting data and information, and the Office of the Interconnection, considering advice and recommendation from the Market Monitoring Unit, shall reject a request for a resource to offer as a Capacity Performance Resource if the Capacity Market Seller does not demonstrate that it can reasonably be expected to meet its Capacity Performance obligations consistent with the resource's offer by the relevant Delivery Year. The Office of Interconnection shall provide its determination to reject eligibility of the resource as a Capacity Performance Resource, and notify the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(b) Offers from External Generation Capacity Resources for the 2020/2021 Delivery Year and Subsequent Delivery Years—General Rule

For the 2020/2021 Delivery Year and any subsequent Delivery Year and for Capacity Performance Resource Sell Offers in any RPM Auction conducted for the 2018/2019 Delivery Year or 2019/2020 Delivery Year after May 9, 2017, unless excepted pursuant to subsection (c) below, a Capacity Market Seller may submit a Sell Offer for an external Generation Capacity Resource in an RPM Auction if the Capacity Market Seller demonstrates to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) The Capacity Market Seller has obtained a determination that the Pseudo-Tie required for its external Generation Capacity Resource is feasible, including (without limitation) that such Pseudo-Tie meets the following requirements:

(A) the external Generation Capacity Resource must have a minimum Electrical Distance impedance equal to or less than 0.065 p.u.; or is within one station of a transmission bus that has a minimum Electrical Distance impedance equal to or less than 0.065 p.u. With regard to this Electrical Distance requirement, the Office of the Interconnection shall:

(1) post on its website the material assumptions, applicable to all tested generators, implemented in the modeling software used to conduct the Electrical Distance analysis (e.g., the general process used to define the facilities included in the Electrical Distance requirement and analysis for each Pseudo-Tie applicant);

(2) upon request by an applicant for a Pseudo-Tie, provide that applicant a copy of the results of the Electrical Distance analysis conducted by the Office of the Interconnection for the specific Pseudo-Tie requested by the applicant, as well as related work papers; and

(3) upon request by an applicant for a Pseudo-Tie, meet with that applicant to discuss specific modeling assumptions and the results of the Electrical Distance analysis for the specific Pseudo-Tie requested by that applicant;

(B) at least one generation resource that has a historic economic minimum offer lower than its historic economic maximum offer, located inside the metered boundaries of the PJM Region, has a minimum flow distribution impact of 1.5 percent on each eligible coordinated flowgate resulting from such Pseudo-Tie. With regard to this requirement, the Office of the Interconnection shall:

(1) post on its website the material assumptions, applicable to all tested generators, that have been implemented in the modeling software used to conduct the analysis to determine whether the requirement has been met (e.g., the definitions of the sink and source used in the market-to-

market analysis and the definition of eligible coordinated flowgates as applicable to the requirement);

(2) upon request by an applicant for a Pseudo-Tie, provide that applicant a copy of the results of the market-to-market flowgate analysis conducted by the Office of the Interconnection for the specific Pseudo-Tie requested by the applicant, as well as related work papers; and

(3) upon request by an applicant for a Pseudo-Tie, meet with that applicant to discuss specific modeling assumptions and the results of the market-to-market flowgate analysis conducted for the specific Pseudo-Tie requested by that applicant;

(C) each external entity with which PJM may be required to coordinate flowgates under an agreed congestion management process maintains a network model that produces results for such flowgates that are within two percent of the results produced by the PJM network model for such flowgates;

(D) the Capacity Market Seller has secured written acknowledgement from the external Balancing Authority Areas that such Pseudo-Tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM.

and the Capacity Market Seller has committed in writing that it will take all steps necessary to implement such Pseudo-Tie prior to the start of the relevant Delivery Year;

(ii) it has, for transmission outside PJM, obtained long-term firm point-to-point transmission service (evaluated for deliverability from the unit-specific physical location of the resource to PJM load pursuant to a study that is reviewed and approved by PJM in accordance with PJM deliverability criteria to ensure uniformity for internal and external resource deliverability requirements), with rollover rights for the term of the transmission service that is confirmed by the Balancing Authority for the Balancing Authority Area where such resource is geographically located; and, as to transmission within PJM, has obtained Network External Designated Transmission Service; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions.

A Capacity Market Seller that satisfies the above requirements with respect to an external Generation Capacity Resource Sell Offer submitted in an RPM Auction for a Delivery Year shall be required to demonstrate satisfaction of such requirements for any Sell Offer with respect to such resource submitted in an RPM Auction for any subsequent Delivery Year, including, without limitation, demonstration that the required external transmission service continues to satisfy PJM's deliverability standards.

(c) Offers from external Generation Capacity Resources for the 2020/2021 Delivery Year and Subsequent Delivery Years—Exception.

A Capacity Market Seller of a Prior CIL Exception External Resource may continue to submit Sell Offers for such resource for any RPM Auction for any Delivery Year up to and including the 2021/2022 Delivery Year (or, solely for any such resource that is (1) owned by a Load Serving Entity and used to self-supply (under arrangements initiated before June 1, 2016, with a duration of at least ten years) such entity's PJM Region load or (2) the subject of a contract for energy or capacity or equivalent written agreement entered into on or before June 1, 2016 for a term of ten years or longer with a purchaser that is an internal PJM load customer, for any Delivery Year during the life of such resource for subparagraph (1) or for the term of the agreement under subparagraph (2)) so long as it continues to comply with all conditions on the grant of its exception to the Capacity Import Limit, subject to the following additional conditions:

(i) for any Delivery Year, beginning with the 2017/2018 Delivery Year, for which such Prior CIL Exception External Resource has cleared an RPM Auction, PJM may in its sole judgment determine that the resource is not Operationally Deliverable for such Delivery Year because it does not satisfy the requirements of subsection (b). If PJM determines a Prior CIL Exception External Resource is not Operationally Deliverable for a Delivery Year, it must notify the Capacity Market Seller of its determination by no later than October 1 immediately preceding such Delivery Year. After receiving such notice, the Capacity Market Seller may elect to:

(A) take the necessary actions to make the Prior CIL Exception External Resource Operationally Deliverable, in PJM's sole judgment, prior to the beginning of such Delivery Year, provided that PJM will, if transmission upgrades are required to make such resource Operationally Deliverable, facilitate the performance of transmission studies and otherwise cooperate with the external Transmission Provider of the system on which such upgrades are required to identify the upgrades required to meet PJM's deliverability standards;

(B) be relieved of its capacity obligation for such Delivery Year by providing written notice of such election to the Office of the Interconnection no later than seven (7) days prior to the posting of planning parameters for the Third Incremental Auction for such Delivery Year as PJM will procure the replacement capacity in the Third Incremental Auction in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii), with no entitlement to any capacity revenues based on such resource, with no requirement to seek replacement for such capacity for such Delivery Year, with no penalty for non-performance or lack of commitment for such Delivery Year, and with no further must-offer obligation that would otherwise arise solely from clearing such capacity for such Delivery Year; or

(C) procure, by purchase or otherwise, replacement in a sufficient quantity to replace the capacity that would have been provided by the Prior CIL Exception External Resource but for PJM's determination that such resource is not Operationally Deliverable.

(ii) Such Capacity Market Seller's continued ability to offer such resource under this exception is conditioned on external Transmission Providers continuing to honor the firm status of the Capacity Market Seller's transmission service for all Delivery Years for which such seller offers such resource under the exceptions provided in this subsection (c).

(iii) A Capacity Market Seller offering and clearing a Prior CIL Exception External Resource pursuant to this subsection (c) shall be relieved of its must-offer obligation that would otherwise arise solely from clearing such capacity. Such relief of the must-offer obligation shall be for any Delivery Year after the last Delivery Year for which it is permitted to offer such resource under this subsection (c).

(iv) PJM will determine key triggers for when a Prior CIL Exception External Resource will not be Operationally Deliverable, including the need for: (1) a remedial action scheme or manual generation dump protocol to manage external transmission emergencies; (2) transmission facility switching arrangements that would have the effect of radializing load in order to manage external transmission emergencies; and (3) "out of market" external Balancing Authority or Transmission Operator directed dispatch instructions to manage excessive or unacceptable frequency of external regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability limit violations.

~~(d) Base Capacity Resources~~

~~For the 2018/2019 and 2019/2020 Delivery Years, following types of Capacity Resources eligible to submit a Sell Offer as a Base Capacity Resource: Generation Capacity Resources, Capacity Storage Resources, Annual Demand Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Each resource that clears a RPM Auction as a Base Capacity Resource must provide energy output to PJM if called during Performance Assessment Intervals occurring in the calendar months of June through September, including any necessary recall of such capacity and energy from service to areas outside the PJM Region. As further detailed in Tariff, Attachment DD, section 10A, Base Capacity Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d).~~

(~~e~~d) Seasonal Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, a Seasonal Capacity Performance Resource shall mean a Summer-Period Capacity Performance Resource or Winter-Period Capacity Performance Resource, as defined below.

i) Summer-Period Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, the following types of Capacity Resources are eligible to submit a Sell Offer as a Summer-Period Capacity Performance Resource: Summer Period Demand Resource, Summer-Period Energy Efficiency Resource, and Capacity Storage Resource, Intermittent Resource, or Environmentally-Limited Resource that has an average expected energy output during summer peak-hour periods consistently and measurably greater than its average expected energy output during winter peakhour periods. To the extent such resource clears an RPM Auction or is otherwise committed as a Summer-Period Capacity Performance Resource, it is obligated to deliver energy as scheduled and/or dispatched by the Office of Interconnection during Performance Assessment Intervals occurring in the calendar months of June through October and the following May of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. As further detailed in Tariff, Attachment DD, section 10A, Summer-Period Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d).

ii) Winter-Period Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, the following types of Capacity Resources are eligible to submit a Sell Offer as a Winter-Period Capacity Performance Resource: Capacity Storage Resource, Intermittent Resource, and Environmentally-Limited Resource that has an average expected energy output during winter peak-hour periods consistently and measurably greater than its average expected energy output during summer peak-hour periods. To the extent such resource clears an RPM Auction or is otherwise committed as a Winter-Period Capacity Performance Resource, it is obligated to deliver energy as scheduled and/or dispatched by the Office of Interconnection during Performance Assessment Intervals occurring in the calendar months of November through April of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. As further detailed in Tariff, Attachment DD, section 10A, Winter-Period Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d).

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered through the 2024/2025 Delivery Year.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered.

i) The Office of the Interconnection shall convert Nominated Energy Efficiency Value to an Unforced Capacity basis by multiplying such value by the Forecast Pool Requirement.

ii) The Office of the Interconnection shall convert the nominated Demand Resource value to a UCAP basis by multiplying such value by, the Forecast Pool Requirement through the 2024/2025 Delivery Year, and starting with the 2025/2026 Delivery Year and for subsequent Delivery Years, the applicable ELCC Class Rating.

iii) Demand Resources and Energy Efficiency Resources shall specify the LDA in which the resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on RAA, Schedule 10.1.

e) Accredited UCAP Factor for Generation Capacity Resources beginning with the 2025/2026 Delivery Year and subsequent Delivery Years.

i) The Accredited UCAP Factor shall be the value established by the Office of the Interconnection in accordance with RAA, Schedule 9.2, prior to the applicable RPM Auction. Such Accredited UCAP Factor shall be multiplied by the ICAP offered to convert the ICAP offered into the UCAP offered.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Accredited UCAP Factor determined by the Office of the Interconnection shall apply to such commitment.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

(g) A Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods, not to exceed the Accredited UCAP of such resource, as applicable. Alternatively, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its Capacity Exchange tools. If any of the commercially aggregated resources in such Sell Offer are subject to the Minimum Floor Offer Price pursuant to Tariff, Attachment DD, section 5.14-(h-2), the Capacity Market Seller that owns or controls such resources may submit a Sell Offer with a Minimum Floor Offer Price of no lower than the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer.

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Tariff, Attachment Q, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Tariff, Attachment DD, section 6.6, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. An external sale of capacity shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Tariff, Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Tariff, Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Tariff, Attachment DD, section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

5.7 Buy Bids

Buy Bids may be submitted in any Incremental Auction. Buy Bids shall specify, as appropriate:

a) The quantity of Unforced Capacity desired, in increments of 0.1 megawatt;

b) The maximum price, in dollars and cents per megawatt per day, that will be paid by the buyer for the megawatt quantity of Unforced Capacity desired;

c) The type of Unforced Capacity desired, i.e., Annual Resource, ~~Extended Summer Demand Resource, or Limited Demand Resource;~~ and

d) The desired LDA for a replacement Capacity Resource. In the event of delay or cancellation of a Qualifying Transmission Upgrade, the Buy Bid shall specify Capacity Resources in the LDA for which such Qualifying Transmission Upgrade was to increase CETL.

5.8 Submission of Sell Offers and Buy Bids

The Office of the Interconnection shall evaluate and accept or reject Sell Offers and Buy Bids submitted by Capacity Market Sellers on the basis of the following requirements and criteria:

a) A Sell Offer or Buy Bid that fails to specify a positive megawatt quantity shall be rejected by the Office of the Interconnection.

b) A Buy Bid that fails to specify price shall be rejected by the Office of the Interconnection. A Sell Offer that fails to either designate such offer as self-scheduled or to specify an offer price shall be rejected by the Office of the Interconnection.

c) A Buy Bid that fails to designate the type of Unforced Capacity desired, i.e., an Annual Resource, ~~Extended Summer Demand Resource, or Limited Demand Resource,~~ shall be rejected by the Office of the Interconnection.

d) All Sell Offers and Buy Bids must be received by the Office of the Interconnection during a specified period, as determined by the Office of the Interconnection, in accordance with the PJM Manuals. A Sell Offer or Buy Bid may be withdrawn by a notification of withdrawal received by the Office of the Interconnection at any time during the foregoing period, but may not be withdrawn after such period.

e) Sell Offers or Buy Bids shall be submitted or withdrawn via the Internet site designated by the Office of the Interconnection; provided, however, that if the Internet site cannot be accessed at any time during the period specified for the applicable auction, a Sell Offer or Buy Bid may be submitted or withdrawn by electronic mail transmitted to the e-mail address, or faxed to the fax number specified by the Office of the Interconnection.

f) Sell Offers must be based on the Capacity Market Seller's Capacity Resource position at the opening of the auction's bidding window.

g) The Office of the Interconnection shall accept a Sell Offer only up to the megawatt amount of installed capacity of Capacity Resources owned or controlled by such Capacity Market Seller that has not previously been committed for the applicable Delivery Year.

h) No Sell Offer shall be accepted from an FRR Entity unless it meets the requirements applicable to such offers under RAA, Schedule 8.1.

i) The Office of the Interconnection shall have final authority to determine whether to accept or reject a Sell Offer in accordance with the terms of the Tariff and the PJM Manuals.

j) A Capacity Market Seller and Capacity Market Buyer may submit any Sell Offer or Buy Bid, respectively, that it chooses or make a decision not to offer a committed resource, provided that the Office of the Interconnection determines that: (i) the Capacity Market Seller has participated in the review process conducted by the Market Monitoring Unit (without regard to whether an agreement is obtained) if required by the Tariff; (ii) the Sell Offer is no higher, in the case of seller market power, or lower, in the case of buyer side market power, than the level to which the Capacity Market Seller has committed or agreed in the course of its participation in such review process; and (iii) the Sell Offer or Buy Bid is compliant with the Tariff and PJM Manuals. Capacity Market Sellers and Capacity Market Buyers assume exclusive responsibility for their Sell Offers and Buy Bids, respectively, and any adverse findings at the Commission related to its Sell Offers and Buy Bids.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, (through the 2024/2025 Delivery Year), the pool-wide average Accredited UCAP Factor (beginning with the 2025/2026 Delivery Year), the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

~~vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year , the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;~~

vi~~i~~) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in Tariff, Attachment DD, section 5.11A;

vii~~i~~) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

~~ix~~viii) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results for each Base Residual Auction shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price.

If PJM discovers a potential error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, along with a description detailing the cause and scope of the error, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. The provided description will not contain information that is market sensitive or confidential. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement~~, minus the Short Term Resource Procurement Target,~~ to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd) through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with Tariff, Attachment DD, section 5.12(a) and section 5.14(a) above.

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b) above; or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in Tariff, Attachment DD, section 5.12(a), and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) above that is entitled to compensation pursuant to section 5.14(b) above; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) above shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with section 5.14(b) above. Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in section 5.14(a) above.

6. The failure to submit a Sell Offer consistent with section 5.14(c)(i)-(iii) above in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) above in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Tariff, Attachment DD, section 5.10(a)(ii).

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under Tariff, Attachment DD, section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in Tariff, Attachment DD, section 5.14B, Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D, Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction, First Incremental, or ~~and~~ Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) [Reserved for future use]~~Minimum Offer Price Rule for Certain New Generation Capacity Resources that are not Capacity Resources with State Subsidy for up to the 2022/2023 Delivery Year.~~

~~(1) The provisions of this section 5.14(h) shall not be effective after the 2022/2023 Delivery Year. For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Tariff, Attachment DD, section 5.10(a)(iv)(A) of this Attachment. This section only applies to new Generation Capacity Resources that do not receive or are not entitled to receive a State Subsidy, meaning that such resources are not Capacity Resources with State Subsidy. To the extent a new Generation Capacity Resource is a Capacity Resource with State Subsidy, then the provisions in Tariff, Attachment DD, section 5.14(h-1) apply.~~

~~The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), and a combined cycle generator ("CC") respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.~~

	~~CONE Area 1~~	~~CONE Area 2~~	~~CONE Area 3~~	~~CONE Area 4~~
~~CT $/MW-yr~~	~~132,200~~	~~130,300~~	~~128,990~~	~~130,300~~
~~CC $/MW-yr~~	~~185,700~~	~~176,000~~	~~172,600~~	~~179,400~~

~~(2) The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in Tariff, Attachment DD, section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.~~

~~(3) For the 2022/2023 Delivery Year, for purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by Tariff, Attachment DD, section 5.10(a)(v-1)(A), provided that the energy and ancillary services revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.501 MMbtu/MWh, the variable operations and maintenance expenses for such resource shall be $2.11 per MWh, a 10% adder will not be included in the energy offer, and the reactive service revenues shall be $3,350 per MW-year.~~

~~(4) Any Sell Offer that is based on either (i) or (ii), and (iii):~~

~~i) a Generation Capacity Resource located in the PJM Region that is submitted in an RPM Auction for a Delivery Year unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM auction for that or any subsequent Delivery Year; or~~

~~ii) a Generation Capacity Resource located outside the PJM Region (where such Sell Offer is based solely on such resource) that requires sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region, unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM Auction for that or any subsequent Delivery Year;~~

~~iii) in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.~~

~~(5) Unit-Specific Exception. A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following process and requirements shall apply to requests for such determinations:~~

~~i) The Capacity Market Seller may request such a determination by no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the minimum offer level expected to be established under subsection (4). If the minimum offer level subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.~~

~~ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues, or, sufficient data for the Office of the Interconnection and the Market Monitoring Unit to produce such an estimate. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may~~

~~include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction- period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer. The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for an exception hereunder.~~

~~The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above.~~

~~For the 2022/2023 Delivery Year, in making such demonstration, the Capacity Market Seller may rely upon revenues projected by well defined, forward-looking dispatch models, designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance costs, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, capacity factors and ancillary service capabilities.~~

~~In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, and plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.~~

~~iii) A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4). Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of an exception hereunder by the Office of the Interconnection.~~

~~iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, the Capacity Market Seller Shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.~~

h-1) [Reserved for future use]~~Minimum Offer Price Rule for Capacity Resources with State Subsidy for the 2022/2023 Delivery Year.~~

~~(1) **General Rule.** The provisions of this section 5.14(h-1) shall not be effective after the 2022/2023 Delivery Year. For the 2022/2023 Delivery Year, any Sell Offer based on either a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with a State Subsidy submitted in any RPM Auction shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the Capacity Market Seller qualifies for an exemption with respect to such Capacity Resource with a State Subsidy prior to the submission of such offer.~~

~~(A) Effect of Exemption. To the extent a Sell Offer in any RPM Auction is based on a Capacity Resource with State Subsidy that qualifies for any of the exemptions defined in Tariff, Attachment DD, sections 5.14(h-1)(4)-(8), the Sell Offer for such resource shall not be limited by the MOPR Floor Offer Price, unless otherwise specified.~~

~~(B) Effect of Exception. To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a Capacity Resource with State Subsidy for which the Capacity Market Seller obtains, prior to the submission of such offer, a resource-specific exception, such offer may include an offer price below the default MOPR Floor Offer Price applicable to such resource type, but no lower than the resource-specific MOPR Floor Offer Price determined in such exception process.~~

~~(C) Process for Establishing a Capacity Resource with a State Subsidy.~~

~~(i) By no later than one hundred and twenty (120) days prior to the commencement of the offer period of any RPM Auction conducted for the 2022/2023 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not each Capacity Resource (other than Demand Resource and Energy Efficiency Resource) that the Capacity Market Seller intends to offer into the RPM Auction qualifies as a Capacity Resource with a State Subsidy (including by way of Jointly Owned Cross-Subsidized Capacity Resource) and identify (with specificity) any State Subsidy. Capacity Market Sellers that intend to offer a Demand Resource or an Energy Efficiency Resource into the RPM Auction shall certify to the Office of Interconnection, in accordance with the PJM Manuals, whether or not such Demand Resource or Energy Efficiency Resource qualifies as a Capacity Resource with a State Subsidy no later than thirty (30) days prior to the commencement of the offer period of any RPM Auction conducted for the 2022/2023 Delivery Year. All Capacity Market Sellers shall be responsible for each certification irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit. A Capacity Resource shall be deemed a Capacity Resource with State Subsidy if the Capacity Market Seller fails to timely certify whether or not a Capacity Resource is entitled to a State Subsidy, unless the Capacity Market Seller receives a waiver from the Commission. Notwithstanding, if a Capacity Market Seller submits a timely resource-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) for the relevant Delivery Year, and PJM approves the resource-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely certified whether or not the resource is a Capacity Resource with State Subsidy.~~

~~(ii) The requirements in subsection (i) above do not apply to Capacity Resources for which the Market Seller designated whether or not it is subject to a State Subsidy and the associated subsidies to which the Capacity Resource is entitled in a prior Delivery Year, unless there has been a change in the set of those State Subsidy(ies), or for those which are eligible for the Demand Resource or Energy Efficiency exemption, Capacity Storage Resource exemption, Self-Supply Entity exemption, or the Renewable Portfolio Standard exemption.~~

~~(iii) Once a Capacity Market Seller has certified a Capacity Resource as a Capacity Resource with a State Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller) that owns or controls such Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Capacity Resource's material change in status as a Capacity Resource with State Subsidy~~

~~within 30 days of such material change, unless such material change occurs within 30 days of the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year, in which case the Market Seller must notify PJM no later than 5 days prior to the commencement of the offer period of any RPM Auction for the 2022/2023 Delivery Year. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection whether its resource meets the criteria of a Capacity Resource with State Subsidy pursuant to Tariff, Attachment DD, section 5.14(h-1)(1)(C)(i).~~

~~(2) **Minimum Offer Price Rule.** Any Sell Offer for a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with State Subsidy that does not qualify for any of the exemptions, as defined in Tariff, Attachment DD, sections 5.14(h-1)(4)-(8), shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Resource with State Subsidy must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process to participate in an RPM Auction.~~

~~(A) New Entry MOPR Floor Offer Price. For a New Entry Capacity Resource with State Subsidy the applicable MOPR Floor Offer Price, based on the net cost of new entry for each resource type, shall be, at the election of the Capacity Market Seller, (i) the resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.~~

~~**Resource Type**~~	~~**Gross Cost of New Entry (2022/2023 $/ MW-day) (Nameplate)**~~
~~Nuclear~~	~~$2,000~~
~~Coal~~	~~$1,068~~
~~Combined Cycle~~	~~$320~~
~~Combustion Turbine~~	~~$294~~
~~Fixed Solar PV~~	~~$271~~
~~Tracking Solar PV~~	~~$290~~
~~Onshore Wind~~	~~$420~~
~~Offshore Wind~~	~~$1,155~~
~~Battery Energy Storage~~	~~$532~~
~~Diesel Backed Demand Resource~~	~~$254~~

~~The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new~~

~~entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For Delivery Years through the 2022/2023 Delivery Year, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types and battery energy storage resource types, the applicable class average EFORd; for wind and solar generation resource types, the applicable class average capacity value factor; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. For the 2023/2024 Delivery Year and subsequent Delivery Years, to determine the applicable UCAP MW-day value, the net cost of new entry is adjusted as follows: for thermal generation resource types, the applicable class average EFORd; for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for Demand Resources and Energy Efficiency Resources, the Forecast Pool Requirement, as applicable to the relevant RPM Auction. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.~~

~~The default New Entry MOPR Floor Offer Price for load-backed Demand Resources (i.e., the MW portion of Demand Resources that is not supported by generation) shall be separately determined for each Locational Deliverability Area as the MW-weighted average offer price of load-backed Demand Resources from the most recent three Base Residual Auctions, where the MW weighting shall be determined based on the portion of each Sell Offer for a load-backed portion of the Demand Resource that is supported by end-use customer locations on the registrations used in the pre-registration process for such Base Residual Auctions, as described in the PJM Manuals.~~

~~For generation-backed Demand Resources that are not powered by diesel generators, the default New Entry MOPR Floor Offer Price shall be the default New Entry MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.~~

~~The default gross cost of new entry for Energy Efficiency Resources shall be $644/ICAP MW-Day, which shall be offset by projected wholesale energy savings, as well as transmission and distribution savings of $95/ICAP MW-Day, to determine the default New Entry MOPR Floor Offer Price (Net Cost of New Entry), where the projected wholesale energy savings are determined utilizing the cost and performance data of relevant programs offered by representative energy efficiency programs with sufficiently detailed publicly available data. The wholesale energy savings, in $/ICAP MW-day, shall be calculated prior to each RPM Auction and~~

~~be equal to the average annual energy savings of 6,221 MWh/ICAP MW times the weighted average of the annual real-time Forward Hourly LMPs of the Zones of the representative energy efficiency programs, where the weighting is developed from the annual energy savings in the relevant Zones, divided by 365.~~

~~To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types except for load-backed Demand Resources and Energy Efficiency Resources, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, combine cycle, and generation-backed Demand Resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue shall be the average of the net energy and ancillary services revenues that the resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of each of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation shall be conducted in accordance with the following and the PJM Manuals:~~

~~(i) for nuclear resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue determined by the product of [average annual day-ahead Forward Hourly LMPs for such Zone, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus reactive services revenue of $3,350/MW-year;~~

~~(ii) for coal resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the Projected EAS Dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using day-ahead~~

~~and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, and daily forecasted coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year;~~

~~(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v-1)(B) for the Reference Resource combustion turbine.~~

~~(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,501 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, plus reactive services revenue of $3,350/MW-year.~~

~~(v) for solar PV resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24 hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time Forward Hourly LMP for such Zone and applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;~~

~~(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24 hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time Forward Hourly LMP for such Zone applicable to such hour with this product summed across all of the hours of an annual period, plus reactive services revenue of $3,350/MW-year;~~

~~(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate for each Zone shall be determined by the gross energy market revenue equal to the product of [the average annual real-time Forward Hourly LMP for such Zone times 8,760 hours times an assumed annual capacity factor of 45%], plus reactive services revenue of $3,350/MW-year;~~

~~(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by the Projected EAS Dispatch of a 1 MW, 4MWh resource, with an 85% roundtrip efficiency, and assumed to be dispatched between 95% and 5% state of charge against day-ahead and real-time Forward Hourly LMPs for such Zone and Forward Hourly Ancillary Service Prices, plus reactive services revenue of $3,350/MW-year; and~~

~~(ix) for generation-backed Demand Resource, the net energy and ancillary services revenue estimate shall be zero dollars.~~

~~New Entry Capacity Resource with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a~~

~~resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.~~

~~(B) Cleared MOPR Floor Offer Prices.~~

~~(i) For a Cleared Capacity Resource with State Subsidy, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the resource-specific MOPR Floor Offer Price , as determined in accordance with Tariff, Attachment DD, section 5.14(h-1)(3) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, net of projected PJM market revenues equal to the resource's net energy and ancillary service revenues for the resource type, as determined in accordance with subsection (ii) below.~~

~~**Existing Resource Type**~~	~~**Default Gross ACR (2022/2023 ($/MW-day) (Nameplate)**~~
~~Nuclear - single~~	~~$697~~
~~Nuclear - dual~~	~~$445~~
~~Coal~~	~~$80~~
~~Combined Cycle~~	~~$56~~
~~Combustion Turbine~~	~~$50~~
~~Solar PV (fixed and tracking)~~	~~$40~~
~~Wind Onshore~~	~~$83~~
~~Diesel-backed Demand Response~~	~~$3~~
~~Load-backed Demand Response~~	~~$0~~
~~Energy Efficiency~~	~~$0~~

~~The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on: for Delivery Years through the 2022/2023 Delivery Year, the resource-specific EFORd for thermal generation resource types, resource-specific capacity value factor for solar and wind generation resource types (based on the ratio of Capacity Interconnection Rights to nameplate capacity, appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction, and for the 2023/2024 Delivery Year and subsequent Delivery Years, the resource-specific~~

~~EFORd for thermal generation resource types and on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.~~

~~Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resources with State Subsidies that have cleared in an RPM Auction for any prior Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.~~

~~For generation-backed Demand Resources that are not powered by diesel generators, the default Cleared MOPR Floor Offer Price shall be the default Cleared MOPR Floor Offer Price applicable to their technology type. Generation-backed Demand Resources using a technology type for which there is no default MOPR Floor Offer Price provided in accordance with this section must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-1)(3) below to participate in an RPM Auction.~~

~~Cleared Capacity Resources with State Subsidy for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a resource-specific value determined in accordance with the resource-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a resource-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.~~

~~(ii) The net energy and ancillary services revenue is equal to forecasted net revenues which shall be determined in accordance with the applicable resource type net energy and ancillary services revenue determination methodology set forth in Tariff, Attachment DD, section 5.14(h-1)(2)(A)(i) through (ix) and using the subject resource's operating parameters as determined in accordance with the PJM Manuals based on (a) offers submitted in the Day-ahead Energy Market and Real-time Energy Market over the calendar year preceding the time of the determination for the RPM Auction; (b) the resource-specific operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs); (c) the resource's EFORd; (d) Forward Hourly LMPs at the generation bus as~~

~~determined in accordance with Tariff, Attachment DD, section 5.10(a)(v-1)(C)(6); and (e) the resource's stated annual revenue requirement for reactive services; plus any unit-specific bilateral contract. In addition, the following resource type-specific parameters shall be considered; (f) for combustion turbine, combined cycle, and coal resource types: the installed capacity rating, ramp rate (which shall be equal to the maximum ramp rate included in the resource's energy offers over the most recent previous calendar year preceding the determination for the RPM Auction), and the heat rate as determined as the resource's average heat rate at full load as submitted to the Market Monitoring Unit and the Office of the Interconnection, where for combined cycle resources heat rates will be determined at base load and at peak load (e.g., without duct burners and with duct burners), as applicable; (g) for nuclear resource type: an average equivalent availability factor of all PJM nuclear resources to account for refueling outages; (h) for solar and wind resource types: the resource's output profiles for the most recent three calendar years, as available; and (i) for battery storage resource type: the nameplate capacity rating (on a MW / MWh basis).~~

~~To the extent the resource has not achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.~~

~~A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Cleared Capacity Resource with State Subsidy based on a net energy and ancillary services revenue determination that does not use the foregoing methodology or parameter inputs stated for that resource type shall, at its election, submit a request for a resource-specific MOPR Floor Offer Price for such Capacity Resource pursuant to Tariff, Attachment DD, section 5.14(h-1)(3) below.~~

~~(3) Resource-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a New Entry Capacity Resource with State Subsidy or a Cleared Capacity Resource with State Subsidy below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a resource-specific exception for such Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the resource-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The resource-specific MOPR Floor Offer Price determined under this provision shall be based on the resource-specific EFORd for thermal generation resource types, on the resource-specific Accredited UCAP value for ELCC Resources (where for solar and wind generation resource types the Accredited UCAP shall be appropriately time-weighted for any winter Capacity Interconnection Rights), or the Forecast Pool Requirement for Demand Resources and Energy Efficiency Resources, as applicable to the relevant RPM Auction and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost were the resource to rely solely on revenues exclusive of any State Subsidy. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:~~

~~(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the resource-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-1)(2)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.~~

~~(B) For a resource-specific exception for a New Entry Capacity Resource with State Subsidy, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.~~

~~The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources and generation-backed Demand Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits for purposes other than state-mandated or state-sponsored programs), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (e.g., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.~~

~~Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately~~

~~reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a resource-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any State Subsidies) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not available, publicly available estimates of future fuel prices may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, capacity factors, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.~~

~~In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.~~

~~The default assumptions for calculating resource-specific Cost of New Entry for Energy Efficiency Resources shall be based on, as supported by documentation provided by the Capacity Market Seller: the nominal-levelized annual cost to implement the Energy Efficiency program or to install the Energy Efficiency measure reflective of the useful life of the implemented Energy Efficiency equipment, and the offsetting savings associated with avoided wholesale energy costs and other claimed savings provided by implementing the Energy Efficiency program or installing the Energy Efficiency measure.~~

~~The default assumptions for calculating resource-specific Cost of New Entry for load-backed Demand Resources shall be based on, as supported by documentation provided by the Capacity Market Seller, program costs required for the resource to meet the capacity obligations of a Demand Resource, including all fixed operating and maintenance cost and weighted average cost of capital based on the actual cost of capital for the entity proposing to develop the Demand Resource.~~

~~For generation-backed Demand Resources, the determination of a resource-specific MOPR Floor Offer Price shall consider all costs associated with the generation unit supporting the Demand Resource, and demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include, but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit.~~

~~(C) For a Resource-Specific Exception for a Cleared Capacity Resource with State Subsidy that is a generation resource, the Capacity Market Seller shall submit a Sell Offer consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller shall, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any State Subsidies) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services market. Such models must utilize publicly available forward prices for electricity and fuel in the PJM Region. Any modifications made to the forward electricity and fuel prices must similarly use publicly available data. Alternative forward prices for fuel may be used if accompanied by contractual evidence showing the applicability of the alternative fuel price. Where forward fuel markets are not avaliable, publicly avaliable estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, capacity factors, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.~~

~~In the alternative, the Capacity Market Seller may request that the Market Monitoring Unit, subject to acceptance by the Office of Interconnection, produce a resource-specific Energy & Ancillary Services Offset value for such resource using the Forward Hourly LMPs, Forward~~

~~Hourly Ancillary Service Prices and either Forward Daily Natural Gas Prices for combustion turbines and combined cycle resources, or forecasted fuel prices for other resource types, plus plant parameters and capability information specific to the dispatch of the resource, as outlined above. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.~~

~~The resource-specific MOPR Floor Offer Price for a Cleared Capacity Resource with State Subsidy that is a generation-backed Demand Resource will be determined based on all costs associated with the generation unit supporting the Demand Resource, and demand charge management benefits at the retail level (as supported by documentation at the end-use customer level) may also be considered as an additional offset to such costs. Supporting documentation (at the end-use customer level) may include but is not limited to, historic end-use customer bills and associated analysis that identifies the annual retail avoided cost from the operation of such generation unit.~~

~~(D) A Sell Offer evaluated at the resource-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a resource-specific exception by the Office of the Interconnection.~~

~~(E) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the resource-specific exception request and that to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.~~

~~(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to~~

~~the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the resource-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the resource-specific determination unless and until ordered to do otherwise by FERC.~~

~~(4) Competitive Exemption.~~

~~(A) A Capacity Resource with State Subsidy may be exempt from the Minimum Offer Price Rule under this subsection 5.14(h-1) in any RPM Auction if the Capacity Market Seller certifies to the Office of Interconnection, in accordance with the PJM Manuals, that the Capacity Market Seller of such Capacity Resource elects to forego receiving any State Subsidy for the applicable Delivery Year no later than thirty (30) days prior to the commencement of the offer period for the relevant RPM Auction. Notwithstanding the foregoing, the competitive exemption is not available to Capacity Resources with State Subsidy that (A) are owned or offered by Self-Supply Entities unless the Self-Supply Entity certifies, subject to PJM and Market Monitor review, that the Capacity Resource will not accept a State Subsidy, including any financial benefit that is the result of being owned by a regulated utility, such that retail ratepayers are held harmless, (B) are no longer entitled to receive a State Subsidy but are still considered a Capacity Resource with State Subsidy solely because they have not cleared an RPM Auction since last receiving a State Subsidy, or (C) are Jointly Owned Cross-Subsidized Capacity Resources or is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) and not all Capacity Market Sellers of the supporting facility unanimously elect the competitive exemption and certify that no State Subsidy will be received associated with supporting the resource (unless the underlying Capacity Resource that is the subject of a bilateral transaction has not received, is not receiving, and is not entitled to receive any State Subsidy except those that are assigned (i.e., renewable energy credits) to the off-takers of a bilateral transaction and the Capacity Market Seller of such Capacity Resource can demonstrate and certify that the Capacity Market Seller's rights and obligations of its share of the capacity, energy, and assignable State Subsidy associated with the underlying Capacity Resource are in pro rata shares). A new Generation Capacity Resource that is a Capacity Resource with State Subsidy may elect the competitive exemption; however, in such instance, the applicable MOPR Floor Offer Price will be determined in accordance with the minimum offer price rules for~~

~~certain new Generation Capacity Resources as provided in Tariff, Attachment DD, section 5.14(h), which apply the minimum offer price rule to the new Generation Capacity Resources located in an LDA where a separate VRR Curve is established as provided in Tariff, Attachment DD, section 5.14(h)(4).~~

~~(B) The Capacity Market Seller shall not receive a State Subsidy for any part of the relevant Delivery Year in which it elects a competitive exemption or certifies that it is not a Capacity Resource with State Subsidy.~~

~~(5) Self-Supply Entity exemption. A Capacity Resource that was owned, or bilaterally contracted, by a Self-Supply Entity on December 19, 2019, shall be exempt from the Minimum Offer Price Rule if such Capacity Resource remains owned or bilaterally contracted by such Self-Supply Entity and satisfies at least one of the criteria specified below:~~

~~(A) has successfully cleared an RPM Auction prior to December 19, 2019;~~

~~(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or~~

~~(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.~~

~~(6) Renewable Portfolio Standard Exemption. A Capacity Resource with State Subsidy shall be exempt from the Minimum Offer Price Rule if such Capacity Resource (1) receives or is entitled to receive State Subsidies through renewable energy credits or equivalent credits associated with a state-mandated or state-sponsored renewable portfolio standard ("RPS") program or equivalent program as of December 19, 2019 and (2) satisfies at least one of the following criteria:~~

~~(A) has successfully cleared an RPM Auction prior to December 19, 2019;~~

~~(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or~~

~~(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.~~

~~(7) Demand Resource and Energy Efficiency Resource Exemption.~~

~~(A) A Capacity Resource with State Subsidy that is Demand Resource or an Energy Efficiency Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Resource satisfies at least one of the following criteria:~~

~~(i) has successfully cleared an RPM Auction prior to December 19, 2019. For purposes of this subsection (A), individual customer location registrations that participated as Demand Resource and cleared in an RPM Auction prior to December 19, 2019, and were submitted to PJM no later than 45 days prior to the BRA for the 2022/2023 Delivery Year shall be deemed eligible for the Demand Resource and Energy Efficiency Resource Exemption; or~~

~~(ii) has completed registration on or before December 19, 2019; or~~

~~(iii) is supported by a post-installation measurement and verification report for Energy Efficiency Resources approved by PJM on or before December 19, 2019 (calculated for each installation period, Zone and Sub-Zone by using the greater of the latest approved post-installation measurement and verification report prior to December 19, 2019 or the maximum MW cleared for a Delivery Year across all auctions conducted prior to December 19, 2019).~~

~~(B) All registered locations that qualify for the Demand Resource and Energy Efficiency Resource exemption shall continue to remain exempt even if the MW of nominated capacity increases between RPM Auctions unless any MW increase in the nominated capacity is due to an investment made for the sole purpose of increasing the curtailment capability of the location in the capacity market. In such case, the MW of increased capability will not be qualified for the Demand Resource and Energy Efficiency Resource exemption.~~

~~(8) Capacity Storage Resource Exemption. A Capacity Resource with State Subsidy that is a Capacity Storage Resource shall be exempt from the Minimum Offer Price Rule if such Capacity Storage Resource satisfies at least one of the following criteria:~~

~~(A) has successfully cleared an RPM Auction prior to December 19, 2019;~~

~~(B) is the subject of an interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement executed by the interconnection customer on or before December 19, 2019; or~~

~~(C) is the subject of an unexecuted interconnection construction service agreement, interim interconnection service agreement, interconnection service agreement or wholesale market participation agreement filed by PJM with the Commission on or before December 19, 2019.~~

~~(9) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with State Subsidy. In the event the Office of the Interconnection, with advice and input from the Market Monitoring Unit, reasonably believes that a certification of a Capacity Resource's status contains fraudulent or material~~

~~misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource is a Capacity Resource with a State Subsidy (including whether the Capacity Resource is a Jointly Owned Cross-Subsidized Capacity Resource) or does not qualify for a competitive exemption or contains information that is inconsistent with the resource-specific exception, then:~~

~~(A) A Capacity Market Seller shall, within five (5) business days upon receipt of the request for additional information, provide any supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate whether such Capacity Resource is a Capacity Resource with State Subsidy or whether the Capacity Market Seller is eligible for the competitive exemption. If the Office of the Interconnection determines that the Capacity Resource's status as a Capacity Resource with State Subsidy is different from that specified by the Capacity Market Seller or is not eligible for a competitive exemption pursuant to subsection (4) above, the Office of the Interconnection shall notify, in writing, the Capacity Market Seller of such determination by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, if the Office of Interconnection determines that the subject resource is a Capacity Resource with State Subsidy or is not eligible for a competitive exemption pursuant to subsection (4) above, such Capacity Resource shall be subject to the Minimum Offer Price Rule, unless and until ordered to do otherwise by FERC.~~

~~(B) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least sixty-five (65) days before the start of the relevant RPM Auction, then the Office of the Interconnection may file the certification that contains any alleged fraudulent or material misrepresentation or omission with FERC. In such event, if the Office of Interconnection determines that a resource is a Capacity Resource with State Subsidy that is subject to the Minimum Offer Price Rule, the Office of the Interconnection will proceed with administration of the Tariff and market rules on that basis unless and until ordered to do otherwise by FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and~~

~~(C) prior to applying the Minimum Offer Price Rule, the Office of the Interconnection, with advice and input of the Market Monitoring Unit, shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged fraudulent or material misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may submit a revised certification for that Capacity Resource for subsequent RPM Auctions, including RPM Auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection to be requested in any filing to FERC shall not~~

~~be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.~~

h-2) Minimum Offer Price Rule Effective with the 2023/2024 Delivery Year

(1) **Certification Requirement.**

(A) By no later than one hundred and fifty (150) days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection for each Generation Capacity Resource the Capacity Market Seller intends to offer into the RPM Auction, in accordance with the PJM Manuals:

(i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification; and

(ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

(B) All Capacity Market Sellers shall be responsible for the accuracy of each certification and its conformance with the Tariff irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.

(C) Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the certification requirements in subsection (A)(i) above do not apply and the status of such Generation Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller of the underlying resource) that owns or controls such Generation Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

(2) **Determining Generation Capacity Resources Subject to the Minimum Offer Price Rule.**

(A) Conditioned State Support.

(i) If the Office of the Interconnection reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource, the Office of Interconnection shall submit, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, a filing at FERC indicating the Office of the Interconnection's intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource reasonably expected to receive such Conditioned State Support. If FERC has already ruled on whether a specific government program or policy constitutes Conditioned State Support and such policy or program is listed in Tariff, Attachment DD-3, the Office of the Interconnection shall not be required to submit the filing described in the preceding sentence.

(ii) Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to: policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., Cross-State Air Pollution Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

(iii) Upon FERC acceptance (whether by order or operation of law) that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i) that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, will be subject to the provisions of the Minimum Offer Price Rule.

(B) Exercise of Buyer-Side Market Power

(i) If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource, then the underlying Capacity Resource shall be subject to the MOPR pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i). If the Office of the Interconnection and/or the Market Monitoring Unit reasonably suspects that a certification submitted under Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii) contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. During such fact-specific review, the Capacity Market Seller will have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource would not be an Exercise of Buyer-Side Market Power. The Office of the Interconnection and/or the Market Monitoring Unit shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year.

In initiating a review, the Office of the Interconnection and/or the Market Monitoring Unit shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. The Office of the Interconnection and/or the Market Monitoring Unit may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, the Office of the Interconnection and the Market Monitoring Unit shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by the Office of the Interconnection and/or the Market Monitoring Unit, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the Office of the Interconnection, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource that could be an Exercise of Buyer-Side Market Power, as follows:

(a) To determine whether a Capacity Market Seller may have Buyer Side Market Power associated with the Generation Capacity Resource for the applicable RPM Auction, the Office of the Interconnection and/or the Market Monitoring Unit will perform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.

(b) To determine whether the Capacity Market Seller's submission of a Sell Offer at any given price level for such Generation Capacity Resource may constitute an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall perform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically. In this analysis, the Office of Interconnection and/or the Market Monitoring Unit shall consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices. If the expected benefit outweighs the expected cost, the Capacity Market Seller shall be deemed to have the incentive to exercise Buyer Side Market Power. If a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not to have the incentive to exercise Buyer Side Market Power with respect to that resource. Out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review.

(ii) The following nonexhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review initiated pursuant to subsection (i) above: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller's long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power.

(iii) Based on the foregoing tests and fact-specific review, including the facts and circumstances of the Generation Capacity Resource, the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, determines that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, the Office of the Interconnection shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the Office of the Interconnection's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on its determination hereunder unless FERC by order directs otherwise.

(C) Failure to timely submit a certification. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications required under Tariff, Attachment DD, section 5.14(h-2)(1) shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) for the relevant Delivery Year, and PJM approves the unit-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

(3) **Minimum Offer Price Rule.** Any Sell Offer for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process, and the unit-specific MOPR Floor Offer Price shall establish the offer level for such resource.

(A) New Entry MOPR Floor Offer Price. For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource, or any uprate of such Generation Capacity Resource participating in the generation interconnection process under Tariff, Part IV, Subpart A, that has not cleared an RPM Auction for any Delivery Year, the applicable MOPR Floor Offer Price, based on the net cost of new entry for the resource type, shall be, at the election of the Capacity Market Seller, (i) the unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-2)(4) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	Through the 2025/2026 Delivery Years: Gross Cost of New Entry (2022/2023 $/ MW-day)	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry

	(Nameplate)	(2026/2027 $/ MW-day) (Nameplate)
Nuclear	$2,000	$2,568
Coal	$1,068	$1,480
Combined Cycle	$320	$540
Combustion Turbine	$294	$427
Fixed Solar PV	$271	$298
Tracking Solar PV	$290	$321
Onshore Wind	$420	$438
Offshore Wind	$1,155	$1,351
Battery Energy Storage	$532	$502

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For the 2023/2024 and 2024/2025 Delivery Years, the net cost of new entry is adjusted using: for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for all other generation resource types, the applicable class average EFORd. For the 2025/2026 Delivery Year and subsequent Delivery Years, the net cost of new entry is adjusted by the applicable class average Accredited UCAP Factor. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue is equal to the average of the annual net revenues of the three most recent calendar years preceding the Base Residual Auction, where such annual net revenues shall be determined in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus an ancillary services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate shall be determined by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using applicable coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,553 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in Peak-Hour Dispatch, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary services revenue shall be $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate shall be the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%], plus an ancillary services revenue of $3,350/MW-year; and

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily twenty-four hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same twenty-four hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has not previously cleared an RPM Auction for that or any prior Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices.

For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the unit-specific MOPR Floor Offer Price, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(4) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent for the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of projected PJM market revenues equal to the resource's historical net energy and ancillary service revenues consistent with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	**Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate)**	**For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/ MW-day) Nameplate**
Nuclear - single	$697	$591
Nuclear - dual	$445	$537
Coal	$80	$94
Combined Cycle	$56	$113
Combustion Turbine	$50	$52
Steam Oil & Gas	NA	$64
Solar PV (fixed and tracking)	$40	$70
Wind Onshore	$83	$147

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. Through the 2024/2025 Delivery Year, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights) or the resource-specific EFORd for all other generation resource types. Effective for the 2025/2026 Delivery Year and subsequent Delivery Years, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, based on the resource's Accredited UCAP Factor. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default Avoidable Cost Rates in the table above, and post the adjusted values on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted Avoidable Cost Rates, the Office of the Interconnection shall utilize the 10-year average Handy-Whitman Index in order to adjust the Gross ACR values to account for expected inflation. Updated estimates of the net energy and ancillary service revenues shall be determined on a resource-specific basis in accordance with Tariff, Attachment DD, section 6.8(d) and the PJM Manuals.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction for any Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(4) **Unit-Specific Exception**. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Capacity Resource. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is under a fact-specific review for Buyer-Side Market Power pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), and where the offer is below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Generation Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the unit-specific MOPR Floor Offer Price, shall be

permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The unit-specific MOPR Floor Offer Price determined under this provision shall be based on the unit-specific Accredited UCAP value for battery energy storage resource types and for solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights) or on the unit-specific EFORd for all other generation resource types, and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of the resource. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the unit-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-2)(3)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(B) For a unit-specific exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has never cleared an RPM Auction, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits or any other revenues outside of PJM markets that do not constitute Conditioned State Support), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (e.g., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a unit-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside the PJM market not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, which may include Maintenance Adders, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

(C) For a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, the Capacity Market Seller shall submit a Sell Offer consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower

RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, which may include Maintenance Adders, and emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

(D) A Sell Offer evaluated at the unit-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection, and that out-of-market compensation is not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices. Failure to adequately support such claimed cost advantages or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in the elimination of consideration of the unsupported element(s) of a unit-specific exception by the Office of the Interconnection.

(E) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the unit-specific exception request and that to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the unit-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the unit-specific determination unless and until ordered to do otherwise by FERC.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export (“Export Reserved Capacity”) multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) above also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving

Entities under Tariff, Attachment DD, section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) above times the Export Customer's Allocated Share determined as follows:

Export Customer’s Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

“Export Path Import” means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource above $0/MW-day, except as described in Tariff, Attachment DD, section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource as outlined in Tariff, Attachment M-Appendix, section II.G. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) Business Day of the Office of the Interconnection's rejection of such

Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under section 6.6(a) above shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 above and Tariff, Attachment M-Appendix, section II.H.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e) below, in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined section 6.8 below.

Maximum Avoidable Cost Rates by Technology Class								
Technology	**2013/14 Mothball ACR ($/MW-Day)**	**2013/14 Retirement ACR ($/MW-Day)**	**2014/15 Mothball ACR ($/MW-Day)**	**2014/15 Retirement ACR ($/MW-Day)**	**2015/16 Mothball ACR ($/MW-Day)**	**2015/16 Retirement ACR ($/MW-Day)**	**2016/2017 Mothball ACR ($/MW-Day)**	**2016/2017 Retirement ACR ($/MW-Day)**
Nuclear	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pumped Storage	$23.64	$33.19	$24.56	$34.48	$25.56	$35.89	$24.05	$33.78
Hydro	$80.80	$105.67	$83.93	$109.76	$87.35	$114.24	$82.23	$107.55
Sub-Critical Coal	$193.98	$215.02	$201.49	$223.35	$209.71	$232.46	$197.43	$218.84
Super Critical Coal	$200.41	$219.21	$208.17	$227.70	$216.66	$236.99	$203.96	$223.10
Waste Coal - Small	$255.81	$309.83	$265.72	$321.83	$276.56	$334.96	$260.35	$315.34
Waste Coal – Large	$94.61	$114.29	$98.27	$118.72	$102.28	$123.56	$96.29	$116.32
Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CC-2 on 1 Frame F	$35.18	$49.90	$36.54	$51.83	$38.03	$53.94	$35.81	$50.79
CC-3 on 1 Frame E/Siemens	$39.06	$52.89	$40.57	$54.94	$42.23	$57.18	$39.75	$53.83
CC–3 or More on 1 or More Frame F	$30.46	$42.28	$31.64	$43.92	$32.93	$45.71	$30.99	$43.03
CC-NUG Cogen. Frame B or E Technology	$130.76	$175.71	$135.82	$182.52	$141.36	$189.97	$133.09	$178.83
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$27.96	$37.19	$29.04	$38.63	$30.22	$40.21	$28.45	$37.85
CT - 1st & Gen. Frame B	$27.63	$36.87	$28.70	$38.30	$29.87	$39.86	$28.11	$37.52
CT - 2nd Gen. Frame E	$26.26	$35.14	$27.28	$36.50	$28.39	$37.99	$26.73	$35.77
CT - 3rd Gen. Aero (GE LM 6000)	$63.57	$93.70	$66.03	$97.33	$68.72	$101.30	$64.70	$95.37
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$33.34	$49.16	$34.63	$51.06	$36.04	$53.14	$33.93	$50.03
CT - 3rd Gen. Frame F	$26.96	$38.83	$28.00	$40.33	$29.14	$41.98	$27.43	$39.52
Diesel	$29.92	$37.98	$31.08	$39.45	$32.35	$41.06	$30.44	$38.66

Oil and Gas Steam	$74.20	$90.33	$77.07	$93.83	$80.21	$97.66	$75.51	$91.94

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the applicable ACR rates, the Office of the Interconnection shall use the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission ("Handy-Whitman Index") to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The ACR rates shall be expressed in dollar values for the applicable Delivery Year.

Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year)		
Technology	**Mothball ACR ($/MW-Day)**	**Retirement ACR ($/MW-Day)**
Combustion Turbine - Industrial Frame	$24.13	$33.04
Coal Fired	$136.91	$157.83
Combined Cycle	$29.58	$40.69
Combustion Turbine - Aero Derivative	$26.13	$37.18
Diesel	$25.46	$32.33
Hydro	$68.78	$89.96
Oil and Gas Steam	$63.16	$76.90
Pumped Storage	$20.12	$28.26

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

~~To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and~~

~~mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.~~

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in Tariff, Attachment M-Appendix, section II.H, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in section 6.8 below, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to Tariff, Attachment M-Appendix, section II.E.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in section 6.4 above). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues: Projected PJM Market Revenues are defined by section 6.8(d) below, for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR + CPQR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

  - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

  - **AFAE (Avoidable Fuel Availability Expenses) c**onsists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource

- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer ~~(or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years)~~, such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

- **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor, applied in accordance with the terms specified below. CRF values are calculated for recovery periods of 4, 5, 10, 15, 20, 25, and 30 years, using the following formula with assumptions of the following components: (i) capital structure and cost of capital; (ii) debt interest rate; (iii) state income tax rate, and (iv) federal income tax and depreciation rates as utilized by the U.S. Internal Revenue Service.

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{m_j}{(1+r)^j}\right]}{(1-s)\sqrt{1+r}\,[(1+r)^N - 1]}$$

Where:
r is the after tax Weighted Average Cost of Capital (calculated as: percent equity * cost of equity + percent debt * debt interest rate * (1- effective tax rate))
s is the effective tax rate (calculated as: State Tax Rate + Federal Tax Rate*(1-State Tax Rate))
B is the bonus depreciation percent
N is the cost recovery period (years)
L is the lessor of N or 16 (years)
m_j is the modified accelerated cost recovery system (MACRS) depreciation factor for year j =1, . . ., 16.

The CRF values of the following table shall be used for RPM Auctions through and including the Base Residual Auction conducted for 2022/2023 Delivery Year. Thereafter, the table of CRF values applicable to each RPM Auction shall be determined and posted on the PJM website by no later than 150 days prior to the commencement of the offer period of the RPM Auction. The values of the posted CRF table shall be determined using federal income tax laws in effect at the time of the determination for the relevant Delivery Year and shall use the same assumptions of (i) capital structure and cost of capital; (ii) debt interest rate; and (iii) state income tax rate, as those utilized to calculate the Cost of New Entry for the Reference Resource for the relevant Delivery Year. For the purpose of the CRF determination, the state income tax rate will be set equal to the average state income tax rate used to calculate the Cost of New Entry of the Reference Resource across the four CONE Regions. The CRF for the 40 Plus Alternative option shall be set equal to 1.1 and is not calculated by the formula above.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above or posted table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above or posted table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Tariff, Part V. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under Tariff, Attachment DD, section 5.14(c).

- **ARPIR (Avoidable Refunds of Project Investment Reimbursements)** consists of avoidable refund amounts of Project Investment

Reimbursements payable by a Generation Owner to PJM under Tariff, Part V, section 118 or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Tariff, Part V, section 119 and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) Variable costs that are directly attributable to the production of energy shall be excluded from a Market Seller's generation resource Avoidable Cost Rate.

(d) For Delivery Years up to and including the 2021/2022 Delivery Year and for the 2023/2024 Delivery Year and subsequent Delivery Years, projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity Market Seller's fuel and environmental costs for the resource which shall be determined either by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agreement and PJM Manuals that are not fuel or environmental costs.

The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

(d-1) For the 2022/2023 Delivery Year, Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall be equal to forecasted net revenues, which shall be determined in accordance with Tariff, Attachment DD, section 5.14(h-1)(2)(B)(ii), or for resource types not specified in such section, in a manner consistent with the methodologies described in such section, that utilizes Forward Hourly LMPs and Forward Hourly Ancillary Service Prices for such resource, forecasted fuel prices as applicable, as well as resource-specific operating parameters and capability information specific to the simulated dispatch of such resource, where such dispatch shall either consider the hourly output profiles for Intermittent Resources in a manner consistent with solar and onshore wind methodologies, or utilize the Projected EAS Dispatch. To the extent the resource has achieved commercial operation, the dispatch shall utilize the resource-specific operating parameters as determined in accordance with the PJM Manuals based on offers submitted in the Day-ahead Energy Market and Real-time Energy Market, as well as the operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs). Adjustments to resource-specific operating parameters may be submitted to the Market Monitoring Unit and the Office of the Interconnection for review and consideration in the simulated dispatch with supporting documentation. For resources that have not yet achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

In the alternative, the Capacity Market Seller may provide their own estimate of Projected PJM Market Revenues to the Market Monitoring Unit and the Office of the Interconnection for review and approval. Such a request shall identify all revenue sources (exclusive of any State Subsidies), including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standards prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize forward prices for energy, ancillary service and fuel in the PJM Region based on contractual evidence of an alternative fuel price or sourced from liquid forward markets (where available), and other publicly available data to develop the forward prices used in the estimate. Where forward fuel markets are not available, publicly available estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, capacity factors, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

8. CAPACITY RESOURCE DEFICIENCY CHARGE

8.1

A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resource~~, Extended Summer Demand Resource, or Limited Demand Resource~~) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:

a) Unit Derating – Such Capacity Resource is a Generation Capacity Resource and its capacity value is derated prior to or during the Delivery Year;

b) EFORD Increase – Such Capacity Resource is a Generation Capacity Resource and the EFORD value determined for such resource at least two (2) months prior to the Third Incremental Auction is higher than the EFORD value submitted in the Capacity Market Seller's cleared Sell Offer;

c) External Generation Resource – Such Capacity Resource is an Existing Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;

d) Planned Generation Resource – Such Capacity Resource is a Planned Generation Capacity Resource and Interconnection Service has not commenced as to such resource prior to the start of the Delivery Year;

e) Planned Demand Resource - Such Capacity Resource is a Planned Demand Resource or an Energy Efficiency Resource and the associated demand response program or energy efficiency measure is not installed prior to the start of the Delivery Year; or

f) Existing Demand Resource – Such Capacity Resource is an existing Demand Resource or Energy Efficiency Resource and, subject to section 8.4 below, is not capable of providing the megawatt quantity of load response specified in the cleared Sell Offer for the time periods of availability associated with the product type.

8.2. Capacity Resource Deficiency Charge

The Capacity Resource Deficiency Charge shall equal the Daily Deficiency Rate (as defined in Tariff, Attachment DD, section 7) multiplied by the megawatt quantity of deficiency below the level of capacity committed in such Capacity Market Seller's Sell Offer(s) or bilateral capacity commitments, or Locational UCAP Seller's Locational UCAP sale for each day such seller is deficient, provided, however, that a resource that is subject to a charge under this section that is also subject to a charge under Tariff, Attachment DD, section 10A hereof for a Performance Shortfall during one or more Performance Assessment Intervals occurring during the period of resource deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Tariff, Attachment DD, section 10A, but shall not be assessed a charge under both this section and Tariff, Attachment DD, section 10A for such simultaneous occurrence of a resource deficiency and Performance Shortfall.

8.3. Allocation of Revenue Collected from Capacity Resource Deficiency Charges

The revenue collected from the assessment of a Capacity Resource Deficiency Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

8.4 Relief from Charges

A Capacity Market Seller or Locational UCAP Seller that is otherwise subject to the Capacity Resource Deficiency Charge solely as a result of section 8.1(f) above may receive relief from such Charge if it demonstrates that the inability to provide the level of demand response specified in its Sell Offer is due to the permanent departure (due to plant closure, efficiency gains, or similar reasons) from the Transmission System of load that was relied upon for load response in such Sell Offer; provided, however, that such seller must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief. Such seller shall receive no RPM Auction Credit for the amount of reduction in the committed Existing Demand Resources.

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

(a) For the 2018/2019 Delivery Year and any subsequent Delivery Year (and for certain purposes for the 2016/2017 and 2017/2018 Delivery Years as provided in subsections (h) and (i) hereof), each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, and for the 2022/2023 Delivery Year and subsequent Delivery Years each PRD Provider that commits Price Responsive Demand for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources or Price Responsive Demand during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation, demand response resources, or Price Responsive Demand that perform during such hour in excess of the level expected based on commitments (if any) of such resources.

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

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

Performance Shortfall = Expected Performance - Actual Performance

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

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

where

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

The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports, Price Responsive Demand Bonus Performance effective with the 2022/2023 Delivery Year, and Demand Response Bonus Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Interval for which performance by any external Generation Capacity Resource would have helped resolve the Emergency Action that was the subject to the Performance Assessment Hour; and provided further that for any Delivery Year up to and including the 2019/2020 Delivery Year, Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

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

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

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

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

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

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

where

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

and for PRD Provider: Price Responsive Demand Committed

where

Price Responsive Demand Committed = the Nominal PRD Value committed by the PRD Provider in the area defined by the Performance Assessment Interval, adjusted to account for any PRD registrations in such area that were not subject to compliance measurement.

and

Actual Performance =

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

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

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

for each PRD Provider, the actual load reduction provided by the PRD Provider during a Performance Assessment Interval, determined in accordance with RAA, Schedule 6.1.N and the PJM Manuals;

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; and for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Interval, and zero if it is not in service during such Performance Assessment Interval.

Such calculation shall encompass all resources and Price Responsive Demand located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval. ~~For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Interval shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.~~

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

Performance Assessment Interval when the PRD Curve associated with such registration in the PJM Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

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

Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate

Where

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

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

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

(f-1) Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price ~~times the number of days in the Delivery Year~~ for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource or such PRD Provider, where such megawatts shall be based on the maximum Unforced

Capacity committed up through the end of the month in which the PAI occurs, times the number of days in the Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource, where such megawatts shall be based on maximum Unforced Capacity committed up through the end of the month in which the Performance Assessment Interval occurs, times the number of days in the season applicable to such resource.

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

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

and

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

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

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

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

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

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

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

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

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

(j) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year. Notwithstanding, if there are less than six months remaining in the current Delivery Year for which no invoice has been issued, the Office of the Interconnection may, with prior notice to PJM Members, allocate in equal amounts any Non-Performance Charge in the remaining monthly bills for the current Delivery Year plus up to six monthly bills into the following Delivery Year for all Capacity Market Sellers that incur such a Non-Performance Charge (but in no event shall the total Non-Performance Charge be divided in more than nine monthly bills). Provided, for any Non-Performance Charges associated with Performance Assessment Intervals from December 23, 2022 and December 24, 2022, a Capacity Market Seller may elect, by providing notice to the Office of Interconnection by March 17, 2023, to divide the total amount of Non-Performance Charges by either (i) the number of remaining monthly bills in the current Delivery Year (i.e., 3 bills) or (ii) the number of remaining monthly bills in the current Delivery Year plus six additional monthly bills into the following Delivery Year (i.e., 9 bills); provided further, however, that for an election under subsection (ii) above, the monthly Non-Performance Charge shall be levelized to include interest for the six month period following the current Delivery Year, such interest amount being determined at the electric interest rate established by the Federal Energy Regulatory Commission at the time of such election. All interest collected in accordance with this provision shall be allocated to the total pool of bonus performance payments and distributed in accordance with Tariff, Attachment DD, section 10A(g).

11. [Reserved for future use]~~**DEMAND RESOURCE COMPLIANCE PENALTY CHARGE**~~

~~The provisions of this section 11 do not apply to Demand Resources committed as Capacity Performance Resources or Base Capacity Demand Resources. All references to Demand Resources in this section specifically exclude Demand Resources committed as Capacity Performance Resources or Base Capacity Demand Resources.~~

~~(a) The Office of the Interconnection shall separately evaluate compliance of each Demand Resource committed for a Delivery Year, in accordance with procedures set forth in the PJM Manuals and, for Delivery Years through May 31, 2019, shall assess a Demand Resource Compliance Penalty Charge on Capacity Market Sellers that committed Demand Resources and Locational UCAP Sellers that sold Demand Resources that cannot demonstrate the hourly performance of such resource in real-time. The compliance is evaluated separately by Load Management Event in each CAA for Demand Resource Registrations dispatched by the Office of Interconnection. The Demand Resource Compliance Penalty Charge will not be assessed to Demand Resource Registrations that are dispatched on a subzonal basis unless such subzone is defined and publically posted the day before the Load Management Event as set forth in the PJM Manuals. To the extent a Demand Resource Registration cannot respond, another Demand Resource Registration in the same geographic location defined by the PJM dispatch instruction with the same designated lead time and comparable capacity commitment may be substituted. Any Demand Resource Registration used as a substitute during a Load Management Event will have the same obligation to respond to future Load Management Event(s) as if it did not respond to such Load Management Event. Capacity Market Sellers that committed Demand Resources and Locational UCAP Sellers that sold Demand Resources that cannot demonstrate the hourly performance of such Demand Resource Registration in real-time based on the capacity commitment shall be assessed a Demand Resource Compliance Penalty Charge; provided, however, that such under compliance shall be determined on an aggregate basis for all dispatched Demand Resource Registrations committed by the same Capacity Market Seller or same Locational UCAP Seller in a CAA.~~

~~(b) The Demand Resource Compliance Penalty Charge for a Capacity Market Seller in a CAA for the on-peak period, which includes all hours specified in the Reliability Assurance Agreement definition of the Limited Demand Resource, shall equal the lesser of (1/the number of Load Management Events during the on-peak period for which such Demand Resource Registration was dispatched, or 0.50) times the weighted daily revenue rate for such seller's dispatched registration, multiplied by the net under-compliance for such registration in such on-peak period, if any, for such seller resulting from all dispatched registrations it has committed for such Delivery Year for such CAA for each Load Management Event called by the Office of the Interconnection. Net CAA under compliance for the Load Management Event will be prorated to individual under compliant registrations in the CAA based on performance of each registration in order to determine net under compliance(s) for each Demand Resource Registration dispatched. The Demand Resource Compliance Penalty Charge for a Capacity Market Seller in a CAA for the off-peak period,~~

~~which includes all hours specified in the Reliability Assurance Agreement definitions of Extended Summer Demand Resource or Annual Demand Resource, but does not include all hours in the on-peak period, shall equal 1/52 times the weighted daily revenue rate for such Demand Resource Registration dispatched for such seller, multiplied by the net undercompliance for such registration in such off-peak period, if any, for such seller resulting from all dispatched registrations it has committed for such Delivery Year for such CAA for each Load Management Event called by the Office of the Interconnection. If a Load Management Event is comprised of both an on-peak period and an off-peak period then such Demand Resource Compliance Penalty Charge will be the higher of the charges calculated under the prior two sentences. The total Compliance Penalty Charges for the Delivery Year is not to exceed the annual revenue received for such Capacity Market Seller's Demand Resources. The net CAA undercompliance for each such Load Management Event shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable DR Factor and Forecast Pool Requirement: (i) the megawatts of load reduction capability committed by such seller on the day of the Load Management Event for all dispatched resources minus (ii) the megawatts of load reduction actually provided by all such dispatched Demand Resources during such Load Management Event. A seller's net undercompliance in a CAA shall be reduced by the seller's total amount of Capacity Resource deficiency shortfalls on the day of the Load Management Event, determined pursuant to Tariff, Attachment DD, section 8, in a CAA for the seller's committed Demand Resources that are the same product(s) dispatched. The daily revenue rate for a Demand Resource Registration shall be based on the Resource Clearing Price(s) that the Demand Resource, for which such registration is linked, received in the auction(s) in which the Demand Resource cleared. The weighted daily revenue rate for a Capacity Market Seller's Demand Resource registration shall be the average rate for the cleared Demand Resource for which such registration is linked, weighted by the megawatts cleared at each price. The total charge per megawatt that may be assessed on a Capacity Market Seller's Demand Resource Registration in a Delivery Year shall be capped at the weighted daily revenue rate the Capacity Market Seller's Demand Resource Registration would receive in the Delivery Year.~~

~~The Demand Resource Compliance Penalty Charges for a Load Management Event for Limited Demand Resources are assessed daily and initially billed by the later of the month of October during such Delivery Year or the third billing month following the Load Management Event that gave rise to such charge. The initial billing for a Load Management Event for Limited Demand Resources will reflect the amounts due from the start of the Delivery Year to the last day that is reflected in the initial billing. The remaining charges for such Load Management Event will be assessed daily and billed monthly through the remainder of the Delivery Year. The Demand Resource Compliance Penalty Charges for a Load Management Event for Annual or Extended Summer Demand Resources are assessed daily and billed by the later of the month of June following such Delivery Year or the third billing month following the Load Management Event that gave rise to such charge. The billing for the Load Management Event for Annual or Extended Summer Demand Resources will be in a lump sum and reflect the accrued charges for the entire Delivery Year.~~

~~c) Daily revenues from assessment of a Demand Resource Compliance Penalty Charge shall be distributed on a pro-rata basis to Demand Resource Providers and Locational~~

~~UCAP Sellers that provided load reductions in excess of the amount such dispatched Demand Resource Registrations were committed to provide. Such revenue distribution, however, shall not exceed for any Capacity Market Seller's dispatched Demand Resource Registration the quantity of excess megawatts provided by such Capacity Market Seller during a single Load Management Event times 0.20 times the weighted daily revenue rate for such Capacity Market Seller's dispatched Demand Resource Registration. To the extent any such revenues remain after such distribution, the remaining revenues shall be distributed to LSEs based on each LSE's Daily Unforced Capacity Obligation.~~

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of RAA, Schedule 6. Capitalized terms used herein that are not otherwise defined in Tariff, Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three

(3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned

Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for

other Demand Resource Providers targeting the same customers; and

- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

(1) for Delivery Years through the 2024/2025 Delivery Year, as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

● A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

● Supplemental status reports, detailing Demand Resources available, as requested by PJM;

● Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

● Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

● Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer or winter) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer or winter Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place.

Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)
>
> Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:
>
> (WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a ~~Base or~~ Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources – all provisions in RAA, Schedule 6, section L and Tariff, Attachment DD-1, section L shall be effective only through the 2025/2026 Delivery Year. Thereafter, no Energy Efficiency Resources shall qualify to be offered into the RPM Auctions beginning with the 2026/2027 Delivery Year.

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the end-use customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

   - For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

   - For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

   The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a

Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

3.2 Market Settlements.

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

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Operating Agreement, Schedule 1, section 2.

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

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

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

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

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

3.2.2 Regulation.

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

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

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

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

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

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

Estimated opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

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

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

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

Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

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

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the Regulation market performance-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

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

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

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

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

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

During a Market Suspension, the following Regulation components for all Real-time Settlement

Intervals in the Market Suspension period will be determined as follows:

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

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

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

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

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

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 below do not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Reserve Requirements, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

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

Except as provided in section 3.2.3(n) below, if the total offered price for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead

Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve credit.

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

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

(A + B) - C

Where:

A = Start-up Costs

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

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

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

D – (E + F)

Where:

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

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

Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

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

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Operating Agreement, Schedule 1, section 3.2.3(p) below, 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. Allocation to real-time load share under this subsection (b) shall not apply to Direct Charging Energy.

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

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

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

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

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

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

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

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

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Operating Agreement, Schedule 1, section 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) excluding Direct Charging Energy), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

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

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

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

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources) costs for generation resources.

Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

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

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), the output of which is reduced or suspended (or, for Energy Storage Resource Model Participants, the charging of which is increased) at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

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

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

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

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

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts

committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

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

(f-4) A Market Seller of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource 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 or solar generating units, Hybrid Resource or Energy Storage Resource as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-5) If a Market Participant of an Energy Storage Resource Model Participant believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. 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 Participant 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-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

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

(A x B) - C

Where:

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

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

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

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

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

Where:

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

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

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

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

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-~~5~~6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-~~5~~6)(iii) or (B) zero.

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

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section 3.2.3(f-4), plus any cancellation fees paid in accordance with Operating Agreement, Schedule 1, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

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

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

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead

Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12 are not included in the determination of withdrawal deviations;

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

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

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

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

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

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

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

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

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

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

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

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

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

PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by section 3.2.3.(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Operating Agreement, Schedule 1, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

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

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

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

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

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

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

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

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

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

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the dispatch signal and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the dispatch LMP Desired MW for each Real-time Settlement Interval.

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

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

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

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

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

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

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

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

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

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

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

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

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Operating Agreement, Schedule 1, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Operating Agreement, Schedule 1, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. Allocation to real-time load share under this subsection (p) shall not apply to Direct Charging Energy. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, section 1.11.6, the Office of the Interconnection shall allocate the charges to the ratio share of real-time load plus export transactions.

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

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

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

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

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

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

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

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

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with section 3.2.3(p). Allocation to real-time load share under this subsection (q)(i) shall not apply to Direct Charging Energy.

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, section 3.2.3(q)(i). 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). Allocation to real-time load share under this subsection (q)(ii) shall not apply to Direct Charging Energy.

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

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

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

3.2.3A Synchronized Reserve.

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

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

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

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

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

Where:

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

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

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

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

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

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

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

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

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

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve

Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

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

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

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

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

Load Response Participant resources.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

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

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

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

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

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

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

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

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

(A x B) - C

Where:

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

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

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

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Synchronized Reserve].

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

(A x B) - C

Where:

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

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional Condense Energy Use in excess of day-ahead Condense Energy Use in real-time multiplied by A] plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals].

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

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

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

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

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

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

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

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

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

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

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

(A + B + C + D) – (E + F + G + H)

Where:

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

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

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

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

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

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

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

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

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

(g) [Reserved for future use]

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

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve the resource was directed to deploy, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. For each Real-time Settlement Interval where there is not a Synchronized Reserve Event, the megawatts that will be charged shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, or the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

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

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

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

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

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

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

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

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

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

Where:

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

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

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

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

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

(c) Non-Synchronized Reserve Market Clearing Prices

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

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

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

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

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

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

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

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multipled by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

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

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

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

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non- Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

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

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

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

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

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

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

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

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

(zero) – (A + B + C + D)

Where:

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

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

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

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

(e) [Reserved for future use]

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

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

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

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

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

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

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

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

Where:

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

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

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

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

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

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

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

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market

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

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

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

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

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

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

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

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone .

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

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

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

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

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

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

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

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

(A x B) – C

Where:

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

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

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

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Secondary Reserve].

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

(A x B) – C

Where:

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

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

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

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

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

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

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

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

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

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

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B) – (C + D + E + F)

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from a steam-electric generating unit, a Hybrid Resource, or a combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output (or the level of Energy Storage Resource Model Participant charging withdrawals) requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level (or the level of Energy Storage Resource Model Participant charging withdrawals) if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from a steam-electric generating unit, a Hybrid Resource, combined cycle unit, or a combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the

Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules.

(a) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on cost-based offers, which are always parameter limited. Such offers must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such cost-based offers ("parameter limited schedules") shall be considered in the commitment of a resource when the Market Seller does not pass the three pivotal supplier test, as further described in Operating Agreement, Schedule 1, section 6.4.1 and the parallel provisions in Tariff, Attachment K-Appendix, section 6.4.1.

(b) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on market-based offers conforming to parameter limitations ("parameter limited schedules"). Such market-based parameter limited schedules must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such market-based parameter limited schedules shall be considered in the commitment of a resource under the following circumstances:

(i) For Capacity Performance Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert, Hot Weather Alert, Cold Weather Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert for all, or any part, of an Operating Day.

~~(ii) For Base Capacity Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency during hot weather operations during the period of June 1 through September 30; (ii) issues a Maximum Generation Emergency Alert or Hot Weather Alert during hot weather operations during the period of June 1 through September 30; or (iii) schedules units based on the anticipation of a Hot Weather Alert, or a Maximum Generation Emergency or Maximum Generation Emergency Alert during hot weather operations during the period of June 1 through September 30, for all, or any part, of an Operating Day.~~

(c)

~~For the 2014/2015 through 2017/2018 Delivery Years for Generation Capacity Resources other than Capacity Performance Resources, and the 2016/2017 through 2018/2019 Delivery Years for Generation Capacity Resources identified and committed in an FRR Capacity Plan, parameter limited schedules shall be defined for the following parameters:~~

~~(i) Turn Down Ratio;~~

~~(ii) Minimum Down Time;~~

~~(iii) Minimum Run Time;~~

~~(iv) Maximum Daily Starts;~~

~~(v) Maximum Weekly Starts.~~

~~For the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, and for the 2016/2017 Delivery Year and subsequent Delivery Years f~~For Capacity Performance Resources, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual unit on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts;

(vi) Maximum Run Time;

(vii) Start-up Time; and

(viii) Notification Time.

These unit-specific values shall apply for the generating unit unless it is operating pursuant to an exception from those values under subsection (i) hereof due to operational limitations that prevent the unit from meeting the minimum parameters. Throughout the analysis process, the Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's unit-specific parameter limited schedule values.

In order to make its determination of the unit-specific parameter limited schedule values for a unit, the Office of the Interconnection may request that the Capacity Market Seller provide to it and the Market Monitoring Unit certain data and documentation as further detailed in the PJM Manuals. Once the Office of the Interconnection has made a determination of the unit-specific parameter limited schedule values for a unit, those values will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed based on changed operational capabilities of the unit.

A Capacity Market Seller that does not believe its generating unit can meet the unit-specific values determined by the Office of the Interconnection due to actual operating constraints, and who desires to establish adjusted unit-specific parameters for those units may request adjusted unit-specific parameter limitations. Any such request must be submitted to the Office of the Interconnection by no later than the February 28 immediately preceding the first Delivery Year for which the adjusted unit-specific parameters are requested to commence. Capacity Market Sellers shall supply, for each generating unit, technical information about the operational limits to support the requested parameters, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's request for adjusted unit-specific parameter limited schedule values. After it has completed its evaluation of the request, the Office of the Interconnection shall notify the Capacity Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied, by no later than April 15. The effective date of the request, if approved by the Office of the Interconnection, shall be no earlier than June 1.

The operational limitations referenced in this section 6.6 shall be (a) physical operational limitations based on the operating design characteristics of the unit, or (b) other actual physical constraints, including those based on contractual limits, that are not based on the characteristics of the unit. In order for a contractual or other actual constraint to be deemed a physical constraint that can be reflected in its unit-specific parameter limits for a Generation Capacity Resource, the Capacity Market Seller must demonstrate that contractual or other actual constraint is not simply an economic decision but a physical restriction that could not be rectified among any commercial alternatives actually available to it.

(d) [Reserved]

(e) [Reserved]

~~(e) For the 2014/2015 through 2017/2018 Delivery Years, upon receipt of proposed revised parameter limited schedule values from the Market Monitoring Unit, prepared in accordance with the procedures for periodic review included in Tariff, Attachment M-Appendix, section II.B.1, the Office of the Interconnection shall file to revise the Parameter Limited Schedule Matrix in section 6.6(d) above accordingly. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file the values that it determines are appropriate.~~

(f) [Reserved]~~(f) For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall calculate and provide to Market Sellers default values in accordance with Tariff, Attachment M-Appendix, section II.B. The default values set forth in the table in subsection (d) above shall apply for the referenced technology types unless a generating unit is operating pursuant to an exception from the default values under subsection (i) due to physical operational limitations that prevent the unit from meeting the minimum parameters, or any megawatts of the unit are committed as a Capacity Performance Resource in which case the unit-specific or adjusted unit-specific values for the generating unit determined by the Office of the Interconnection shall apply to all megawatts of the generating unit offered into the PJM energy~~

~~markets. For generating units having the ability to operate on multiple fuels, Market Sellers may submit a parameter limited schedule associated with each fuel type.~~

(g) T~~For the 2016/2017 Delivery Year and subsequent Delivery Years, t~~he following additional parameter limits shall apply for Capacity Performance Resources, other than Capacity Storage Resources, submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Capacity Performance Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) The combined start-up and notification times shall not exceed 24 hours, except when a Hot Weather Alert or Cold Weather Alert has been issued;

(ii) When a Hot Weather Alert or Cold Weather Alert has been issued, combined start-up and notification times shall not exceed 14 hours;

(iii) When a Hot Weather Alert or Cold Weather Alert has been issued, notification time shall not exceed one hour; and,

(iv) When a Hot Weather Alert or Cold Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Capacity Performance Resource for both its market-based schedules and cost-based schedules.

Capacity Storage Resources that clear in a Reliability Pricing Model Auction shall, unless the Capacity Market Seller has requested for its Capacity Storage Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and notification time, and/or minimum down time, due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) Have combined start-up and notification times that shall not exceed one hour; and,

(ii) Have a minimum down time that shall not exceed one hour.

(h) [Reserved]
~~For the 2018/2019 and 2019/2020 Delivery Years, the following additional parameter limits for Base Capacity Resources submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Base Capacity Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:~~

~~(i) Combined start-up and notification times shall not exceed 48 hours;~~

~~(ii) When a Hot Weather Alert has been issued, notification time shall not exceed one hour; and,~~

~~(iii) When a Hot Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Base Capacity Resource for both its market-based schedules and cost-based schedules.~~

(i) If a generating unit is or will become unable to achieve the default or unit-specific values determined by the Office of the Interconnection due to actual operating constraints affecting the unit, the Capacity Market Seller of that unit may submit a written request for an exception to the application of those values. Exceptions to the parameter limited schedule default or unit-specific values shall be categorized as either a one-time temporary exception, lasting 30 days or less; a period exception, lasting at least 31 days and no more than one year; or a persistent exception, lasting for at least one year.

(i) Temporary Exceptions. A temporary exception shall be deemed accepted without prior review by the Market Monitoring Unit or the Office of the Interconnection upon submission by the Market Seller of the generating unit of written notification to the Market Monitoring Unit and the Office of the Interconnection, and shall automatically commence and terminate on the dates specified in such notification, which must be for a period of time lasting 30 days or less, unless the termination date is extended pending a request for a period exception or shortened due to a change in the physical conditions of the unit such that the temporary exception is no longer required. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection within three days following the commencement of the temporary exception its documentation explaining in detail the reasons for the temporary exception, and shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Failure to provide a timely response to such request for additional information shall cause the temporary exception to terminate the following day. The Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing of any updates to the physical condition of the unit and shall notify the Office of Interconnection and the Market Monitoring Unit in writing of an early termination of a temporary exception due to changed physical conditions by no later than one Business Day prior to the early termination date. A Market Seller shall provide supporting documentation demonstrating the actual termination date of the physical and actual parameter limitation that prompted the need for the temporary exception to the Office of Interconnection and the Market Monitoring Unit within one Business Day of the termination of such condition. A temporary exception may only be requested one-time for the same physical and actual constraint per occurrence since an operational constraint that may periodically exist more than once should be the subject of a period exception request rather than multiple temporary exception requests.

In addition, if a Market Seller is unaware of the need for a period exception prior to the February 28 deadline for submitting such requests, the Market Seller may utilize the temporary exception process and seek to modify that exception pursuant to the process described below.

Modification of Temporary Exceptions. If, prior to the scheduled termination date the Market Seller determines that the temporary exception must persist for more than 30 days and the Market Seller wants to extend the period for which the exception applies, or if a Market Seller is unaware of the need for a period or persistent exception prior to the February 28 deadline for submitting such requests and the Market Seller has submitted a temporary exception request, it must submit to the Market Monitoring Unit and the Office of the Interconnection a written request to modify the temporary exception to become a period exception or a persistent exception, and provide detailed documentation explaining the reasons for the requested modification of the temporary exception. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period or persistent exception request, and if the exception requested is based on new physical operating limits for the unit for which some or all historical operating data is unavailable, the Market Seller may also submit technical information about the physical operational limits of the unit to support the requested parameters. Such Market Seller shall respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Such request shall be reviewed by the Market Monitoring Unit and must be evaluated by the Office of the Interconnection using the same standard utilized to evaluate period exception and persistent exception requests. Per Tariff, Attachment M-Appendix, section II.B, the Market Monitoring Unit shall evaluate the modification request and provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request. The Office of the Interconnection shall provide its determination whether the request complies with the Tariff and Manuals by no later than 20 Business Days from the date of the modification request. A temporary exception shall be extended and shall not terminate until the date on which the Office of the Interconnection issues its determination of the modification request.

(ii) Period Exceptions and Persistent Exceptions. Market Sellers must submit period exception and persistent exception requests to the Market Monitoring Unit and the Office of the Interconnection by no later than the February 28 immediately preceding the twelve month period from June 1 to May 31 during which the exception is requested to commence. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period exception or persistent exception request, and if the exception requested is based on new physical operational limits for the unit for which some or all historical operating data is unavailable, the generating unit may also submit technical information about the physical operational limits for exceptions of the unit to support the requested parameters. The Market Monitoring Unit shall evaluate such request in accordance with the process set forth in Tariff, Attachment M-Appendix, section II.B. A Market Seller (i) must submit a parameter limited schedule value consistent with an agreement with the Market Monitoring Unit under such process or (ii) if it has not agreed with the Market Monitoring Unit on the parameter limited schedule value, may submit its own value to the Office of the Interconnection and to the Market Monitoring Unit, by no later than April 8. Each exception request must indicate the expected duration of the requested exception including the termination date thereof. The proposed parameter limited schedule value submitted by the Market Seller is subject to approval of the Office of the Interconnection pursuant to the requirements of the Tariff and the PJM Manuals. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the exception request. After it has completed its evaluation of the exception request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the exception request is approved or denied, by no later than April 15. The effective date of the exception, if approved by the Office of the Interconnection, shall be no earlier than June 1 of the applicable Delivery Year. The Office of the Interconnection's determination for an exception shall continue for the period requested and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

The Market Seller shall provide written notification to the Market Monitoring Unit and the Office of the Interconnection of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection in their evaluations of the Market Seller's request for a period or persistent exception. The Market Monitoring Unit shall provide written notification to the Office of the Interconnection and the Market Seller of any change to its determination regarding the exception request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice. The Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, of any change to its determination regarding the exception request, based on the material change in facts, by no later than 20 Business Days after receipt of the Market Seller's notice. If the Office of the Interconnection determines that the exception no longer complies with the Tariff or Manuals, the following parameter values shall apply to all megawatts of the generating unit offered into the PJM energy markets:

~~(1) for generating units for which no megawatts of the unit are commited as Capacity Performance Resources the default values specified in the Parameter Limited Schedule Matrix shall apply for the 2016/2017 through 2017/2018 Delivery years,~~

~~(2) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which no adjusted unit-specific values have been approved by PJM, the Base Capacity Resource unit-specific values determined by PJM shall apply for the 2018/2019 and 2019/2020 Delivery Years,~~

~~*(i)*~~ (1) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply. ~~for the 2016/2017 Delivery Year and subsequent Delivery Years,~~

~~*(ii)* for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which adjusted unit-specific values have been approved by PJM, the Base Capacity Resource adjusted unit-specific values shall apply for the 2018/2019 and 2019/2020 Delivery Years, and~~

(2) ~~5)~~ for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource and for which adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource adjusted unit-specific values shall apply ~~for the 2016/2017 Delivery Year and subsequent Delivery Years~~.

(i) Notwithstanding the foregoing, the provisions of this section 6.6 shall only pertain to the Offer Data a Market Seller must submit to the Office of the Interconnection for its offers into the Day-ahead Energy Market, rebidding period that occurs after the clearing of the Day-ahead Energy Market and Real-time Energy Market, and do not affect or change in any way a Generation Owner's obligation under NERC Reliability Standards to notify the Office of the Interconnection of its actual or expected actual physical operating conditions during the Operating Day.

(k) Notwithstanding anything contrary herein, the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for a generating unit shall be applicable to that generating unit regardless whether there is a change in the owner, operator or Market Seller of the unit because the parameter limited schedule values for the unit are determined based on the physical limitations of the unit, which should not change merely based on a change in owners, operator or Market Seller. Because parameter limited schedule values attach to the generating unit and are not owned by a Market Seller of the unit, when there are multiple owners or Market Sellers for a generating unit, all owners and Market Sellers shall be bound by the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for the unit.

(l) The provisions of this section 6.6 only apply to Generation Capacity Resources, and not to Energy Resources.

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

"Accredited UCAP" shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

"Accredited UCAP Factor" shall mean, through the 2024/2025 Delivery Year, one minus EFORd, and for 2025/2026 Delivery Year and subsequent Delivery Years, the ratio of the Capacity Resource's Accredited UCAP to the Capacity Resource's installed capacity.

Agreement:

"Agreement" shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

"Annual Demand Resource" shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

"Applicable Regional Entity" shall have the same meaning as in the PJM Tariff.

~~**Base Capacity Demand Resource:**~~

~~"Base Capacity Demand Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.~~

~~**Base Capacity Energy Efficiency Resource:**~~

~~"Base Capacity Energy Efficiency Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.~~

~~**Base Capacity Resource:**~~

~~"Base Capacity Resource" shall have the same meaning as in Tariff, Attachment DD.~~

Base Residual Auction:

"Base Residual Auction" shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Capacity Resource or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit" or "CETL" shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

"Capacity Only Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

"Capacity Performance Resource" shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

"Capacity Resources" shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and Reliability Assurance Agreement, Schedule 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; or (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.

Capacity Storage Resource Class:

"Capacity Storage Resource Class" shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours. The characteristic duration of an Energy Storage Resource Class is the ratio of the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

"Capacity Transfer Right" shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

"Coal Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

"Combination Resource" shall mean a Generation Capacity Resource that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall have the same meaning as in the Tariff.

Complex Hybrid Class:

"Complex Hybrid Class" shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Daily Unforced Capacity Obligation:

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

"Delivery Year" shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

"Demand Resource" or "DR" shall mean an ~~Limited Demand Resource, Extended Summer Demand Resource,~~ Annual Demand Resource~~, Base Capacity Demand Resource~~ or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

~~**Demand Resource Factor or DR Factor:**~~

~~"Demand Resource Factor" or "DR Factor" shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6~~

Demand Resource Officer Certification Form:

"Demand Resource Officer Certification Form" shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

"Demand Resource Registration" shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

Effective Nameplate Capacity:

“Effective Nameplate Capacity” shall mean (i) for each Variable Resource and Combination Resource, the resource’s Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output); (ii) for each Limited Duration Resource, the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource’s capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

“Effective UCAP” shall mean a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Class:

“ELCC Class” shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

“ELCC Class Rating” shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

“ELCC Class UCAP” shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

“ELCC Portfolio UCAP” shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

“ELCC Resource” shall mean, through the 2024/2025 Delivery Year, a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource, and beginning with the 2025/2026 Delivery Year, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

“ELCC Resource Performance Adjustment” shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

“Electric Cooperative” shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

“Electric Distributor” shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

"End-Use Customer" shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Members Committee sector classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Efficiency Resource:

"Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources~~, Base Capacity Energy Efficiency Resources~~ and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

"Exigent Water Storage" shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

"Existing Demand Resource" shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery

Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing Generation Capacity Resource:

"Existing Generation Capacity Resource" shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

~~**Extended Summer Demand Resource:**~~

~~"Extended Summer Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.~~

Facilities Study Agreement:

"Facilities Study Agreement" shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall have the meaning specified in the Tariff.

Firm Service Level:

"Firm Service Level" or "FSL" of Price Responsive Demand for the 2022/2023 Delivery Year and subsequent Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when an Emergency Action that triggers a Performance Assessment Interval is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. "Firm Service Level" or "FSL" of Demand Resource shall mean the pre-determined level for which an end-use customer's load shall be reduced, upon notification from the Curtailment Service Provider's market operations center or its agent.

Firm Transmission Service:

"Firm Transmission Service" shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

"Fixed Resource Requirement Alternative" or "FRR Alternative" shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

"Fixed-Tilt Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

"Forecast Pool Requirement" or "FPR" shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

"FRR Capacity Plan" or "FRR Plan" shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

"FRR Entity" shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

"FRR Service Area" shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

"Full Program Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

"Full Requirements Service" shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

"Gas Combined Cycle Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

"Gas Combined Cycle Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

"Gas Combustion Turbine Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

"Gas Combustion Turbine Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

"Generation Capacity Resource" shall mean a Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Capacity Resource Provider:

"Generation Capacity Resource Provider" shall mean a Member that owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity.

Generation Owner:

"Generation Owner" shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hybrid Resource Class:

"Hybrid Resource Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in a Capacity

Storage Resource Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

"Hydropower With Non-Pumped Storage" shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

"Hydropower With Non-Pumped Storage Class" shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

Incremental Auction:

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, Accredited UCAP Factor decrease, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Intermittent Hydropower Class:

"Intermittent Hydropower Class" shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

"IOU" shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Intermittent Landfill Gas Class:

"Intermittent Landfill Gas Class" shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Large Load Adjustment:

"Large Load Adjustment" shall mean any MW quantity of adjustments to summer peak load at the "zone/area" level and summed by Zone as further detailed in PJM Manuals. For purposes of this definition, a "zone/area" is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering (e.g., the service territory of an operating company of a Transmission Owner).

~~**Limited Demand Resource:**~~

~~"Limited Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.~~

Limited Duration Resource:

"Limited Duration Resource" shall mean a Generation Capacity Resource that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Serving Entity or LSE:

"Load Serving Entity" or "LSE" shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

"Locational Reliability Charge" shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

"Markets and Reliability Committee" shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

"Maximum Emergency Service Level" or "MESL" of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Members Committee:

"Members Committee" shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

"Network Resources" shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Nominal PRD Value:

"Nominal PRD Value" shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

"Non-Retail Behind the Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Nuclear Class:

"Nuclear Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

"Obligation Peak Load" shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Offshore Wind Class:

“Offshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

“Onshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean that agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C, on file with the Commission.

Operating Day:

“Operating Day” shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Ordinary Water Storage:

“Ordinary Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

“Other Limited Duration Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

"Other Limited Duration Combination Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

"Other Supplier" shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM's governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

"Other Unlimited Resource Class" shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

"Other Variable Resource Class" shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

"Partial Requirements Service" shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

"Party" shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

"Peak Shaving Adjustment" shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, ~~Base Capacity Demand Resource,~~ Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Performance Assessment Interval:

"Performance Assessment Interval" shall have the meaning specified in Tariff, Attachment DD.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Region:

"PJM Region" shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

"PJM Region Installed Reserve Margin" shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T., "OATT" or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Planned Demand Resource:

"Planned Demand Resource" shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned External Generation Capacity Resource:

"Planned External Generation Capacity Resource" shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has a fully executed system impact study agreement (or other documentation which is functionally equivalent to a System Impact Study Agreement under the PJM Tariff) or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to a Facilities Study Agreement under the PJM Tariff), with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to an Interconnection Service Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network

Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

"Planned Generation Capacity Resource" shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, a System Impact Study Agreement (or, for resources for which a System Impact Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a System Impact Study Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, a Facilities Study Agreement (or, for resources for which a Facilities Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a Facility Studies Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

"Planning Period" shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

"Portfolio Expected Unserved Energy" shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

"PRD Curve" shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

"PRD Provider" shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider's Zonal Expected Peak Load Value of PRD:

"PRD Provider's Zonal Expected Peak Load Value of PRD" shall mean the expected contribution to Delivery Year peak load of a PRD Provider's Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year's peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection's load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

"PRD Reservation Price" shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

"PRD Substation" shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

"Price Responsive Demand" or "PRD" shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection (prior to 2022/2023Delivery Year) or a Performance Assessment Interval that triggers a PRD performance assessment (effective with 2022/2023 Delivery Year), and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

"Price Responsive Demand Credit" shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

"Price Responsive Demand Plan" or "PRD Plan" shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider's Nominal PRD Value.

Public Power Entity:

"Public Power Entity" shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

"Qualifying Transmission Upgrades" shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" or "RERRA" shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

"Reliability Principles and Standards" shall mean the principles and standards established by the Office of the Interconnection that define, among other things, an acceptable probabilistic of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

"Required Approvals" shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

“Self-Supply” shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

“Small Commercial Customer” shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

“State Regulatory Structural Change” shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party’s default service rules that materially affect whether retail choice is economically viable.

Steam Class:

“Steam Class” shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

"Supervisory Control" shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

"Threshold Quantity" shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be determined in accordance with Reliability Assurance Agreement, Schedule 8.1, section D.2.

Tracking Solar Class:

"Tracking Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity:

"Unforced Capacity" shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

"Unlimited Resource" shall mean a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource:

"Variable Resource" shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

Winter Peak Load (or WPL):

"Winter Peak Load" or "WPL" shall mean the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand values may be excluded from the calculation. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

Zonal Capacity Price:

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

Zone or Zonal:

"Zone" or "Zonal" shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

"Zonal Winter Weather Adjustment Factor" or "ZWWAF" shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand

Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the

Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined:

(1) for Delivery Years through the 2024/2025 Delivery Year, as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer or winter) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter

Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer or winter, Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)
>
> Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:
>
> (WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a ~~Base or~~ Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources – all provisions in RAA, Schedule 6, section L and Tariff, Attachment DD-1, section L shall be effective only through the 2025/2026 Delivery Year. Thereafter, no Energy Efficiency Resources shall qualify to be offered into the RPM Auctions beginning with the 2026/2027 Delivery Year.

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the end-use customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

   - For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

   - For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

     The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(ii) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(di) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver

Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

C. Election, and Termination of Election, of FRR Alternative

1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. No later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources~~,~~ and Seasonal Capacity Performance Resources~~, and Base Capacity Resources,~~ as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, except a new FRR Entity's initial election, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

5. Notwithstanding subsections C.1 and C.2 of this Schedule, an FRR Entity that elected the FRR Alternative for a Delivery Year prior to the 2025/2026 Delivery Year, may terminate its election of the FRR Alternative prior to meeting the minimum term of five years without penalty by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for a Delivery Year through the 2028/2029 Delivery Year.

G. Capacity Resource Performance

1. Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, ~~however, through the 2024/2025 Delivery Year,~~ only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

2. For any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources or Seasonal Capacity Performance Resources determined in accordance with the following: For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's FRR Capacity Plan or Price Responsive Demand committed to reduce the FRR Entity's unforced capacity obligation (for the 2022/2023 Delivery Year and subsequent Delivery Years) will be determined in the same fashion as prescribed by the Tariff, Attachment DD, section 10A, and for such hour, a net Performance Shortfall shall be determined separately for Capacity Performance Resources and for Base Capacity Resources. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) exceeds the Expected Performance of such resources or Price Responsive Demand, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Base Capacity Resources for such hour. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Base Capacity Resources exceeds the Expected Performance of such resources, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such hour. For the 2020/2021 Delivery Year, the net Performance Shortfall determined for Capacity Performance Resources and Price Responsive Demand shall include the performance of Seasonal Capacity Performance Resources contained in the FRR Capacity Plan.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources or Price Responsive Demand, if any, for each such Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval to establish the additional MW quantities of Capacity Performance Resources, Seasonal Capacity Performance Resources, or Price Responsive Demand that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Capacity Performance Resources in any Delivery Year shall not exceed a MW quantity equal to 0.5 times the MW quantity of the Capacity Performance Resources and Seasonal Capacity Performance Resources that were committed in the FRR Capacity Plan for such Delivery Year and Price Responsive Demand committed such Delivery Year (for the 2022/2023 Delivery Year and subsequent Delivery Years). The FRR Entity's net Performance Shortfall among Base Capacity Resources, if any, for each such Performance Assessment Interval shall be multiplied by a rate of [(0.00139 MWs/Performance Assessment Interval) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)] to establish the additional MW quantities of Capacity Performance Resources or Seasonal Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Base Capacity Resources in any Delivery Year shall not exceed a MW quantity equal to [(0.5 times the MW quantity of the Base Capacity Resources that were committed in the FRR Capacity Plan for such Delivery Year) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)].

An FRR Entity that elects the physical option shall not be eligible for, or subject to, the revenue allocation described in Tariff, Attachment DD, section 10A(g).

H. Annexation of service territory by Public Power Entity

1. In the event a Public Power Entity that is an FRR Entity annexes service territory to include new customers on sites where no load had previously existed, then the incremental load on such a site shall be treated as unanticipated load growth, and such FRR Entity shall be required to commit sufficient resources to cover such obligation in the relevant Delivery Year.

2. In the event a Public Power Entity that is an FRR Entity annexes service territory to include load from a Party that has not elected the FRR Alternative, then:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, such acquiring FRR Entity shall pay a Locational Reliability Charge for the acquired load.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, such acquiring FRR Entity shall include such incremental load in its FRR Capacity Plan.

3. Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR Entity:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, PJM would consider shifted load as unanticipated load growth for purposes of determining the RTO/LDA Reliability Requirements, ~~Limited Resource and Sub-Annual Constraints for the 2017/2018 Delivery Year, and Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint for the 2018/2019 and 2019/2020 Delivery Years in all future Incremental Auctions for such Delivery Years,~~ and such shifted load shall pay a Locational Reliability Charge. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, the FRR Entity that lost such load would no longer include such load in its FRR Capacity Plan, and PJM would include such shifted load in future BRAs.

Attachment B

Revisions to the
PJM Open Access Transmission Tariff,
PJM Operating Agreement
and PJM Reliability Assurance Agreement

(Clean Format)

Definitions – A - B

30-minute Reserve:

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Affected System:

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

"Affected System Operator" shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

"Agreements" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:

"Ancillary Services" shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

"Annual Resource" shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

Annual Revenue Rate:

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

"Annual Transmission Costs" shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

"Applicable Laws and Regulations" shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

"Applicable Technical Requirements and Standards" shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, "Applicable Technical Requirements and Standards" shall refer to the "PJM Small Generator Interconnection Applicable Technical Requirements and Standards." All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider's internet website.

Applicant:

"Applicant" shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

"Application" shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

"Attachment Facilities" shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

"Attachment H" shall refer collectively to the Attachments to the PJM Tariff with the prefix "H" that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

"Authorized Government Agency" means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

"Balancing Ratio" shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Economic Load Response Participant Resource:

"Batch Load Economic Load Response Participant Resource" shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

"Business Day" shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – C - D

Canadian Guaranty:

"Canadian Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:

"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:

"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Export Transmission Customer:

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:

"Capacity Interconnection Rights" shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:

"Capacity Performance Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Resource:

"Capacity Resource" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource with State Subsidy:

"Capacity Resource with State Subsidy" shall mean (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

Capacity Resource Clearing Price:

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:

"Capacity Storage Resource" shall mean any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan.

Capacity Transfer Right:

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

Capacity Transmission Injection Rights:

"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Charge Economic Maximum Megawatts:

"Charge Economic Maximum Megawatts" shall mean the greatest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Continuous Mode or in Charge Mode. Charge Economic Maximum Megawatts shall be the Economic Minimum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Charge Mode or in Continuous Mode.

Charge Economic Minimum Megawatts:

"Charge Economic Minimum Megawatts" shall mean the smallest magnitude of megawatt power consumption available for charging in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Charge Mode. Charge Economic Minimum Megawatts shall be the Economic Maximum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Charge Mode.

Charge Mode:

"Charge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource that only includes negative megawatt quantities (i.e., the Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource is only withdrawing megawatts from the grid).

Charge Ramp Rate:

"Charge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Charge Mode.

Cleared Capacity Resource with State Subsidy:

"Cleared Capacity Resource with State Subsidy" shall mean a Capacity Resource with State Subsidy that has cleared in an RPM Auction for a Delivery Year that is prior to the 2022/2023 Delivery Year or, starting with 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have cleared an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price and since then, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy have been, the subject of a Sell Offer into the Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for the relevant Delivery Year.

Closed-Loop Hybrid Resource:

"Closed-Loop Hybrid Resource" shall mean a Hybrid Resource that is physically or contractually incapable of charging from the grid.

Cold/Warm/Hot Notification Time:

"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:

For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:

"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:

"Collateral" shall be a cash deposit, including any interest thereon, or a Letter of Credit issued for the benefit of PJM or PJMSettlement, in an amount and form determined by and acceptable to PJM or PJMSettlement, provided by a Participant to PJM or PJMSettlement as credit support in order to participate in the PJM Markets or take Transmission Service. "Collateral" shall also include surety bonds, except for the purpose of satisfying the FTR Credit Requirement, in which case only a cash deposit or Letter of Credit will be acceptable.

Collateral Call:

"Collateral Call" shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Co-Located Resource:

"Co-Located Resource" shall mean a component of a Mixed Technology Facility that operates in the capacity, energy, and/or ancillary services market(s) as a separate resource from the other components of such facility.

Commencement Date:

"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:

The "Committed Offer" shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4, or Operating Agreement, Schedule 1, section 6.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6, for a particular clock hour for an Operating Day.

Completed Application:

"Completed Application" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Composite Energy Offer:

"Composite Energy Offer" for generation resources shall mean the sum (in $/MWh) of the Incremental Energy Offer and amortized Start-Up Costs and amortized No-load Costs, and for Economic Load Response Participant resources the sum (in $/MWh) of the Incremental Energy Offer and amortized shutdown costs, as determined in accordance with Tariff, Attachment K-Appendix, section 2.4 and Tariff, Attachment K-Appendix, section 2.4A and the PJM Manuals.

Conditional Incremental Auction:

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

Conditioned State Support:

"Conditioned State Support" shall mean any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where "conditioned on clearing in any RPM Auction" refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy.

CONE Area:

"CONE Area" shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:

"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constraint Relaxation Logic:

"Constraint Relaxation Logic" shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the Marginal Value of a transmission constraint.

Constructing Entity:

"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:

"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:

"Construction Service Agreement" shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Contingent Facilities:

"Contingent Facilities" shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

Continuous Mode:

"Continuous Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource that includes both negative and positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource is capable of continually and immediately transitioning from withdrawing megawatt quantities from the grid to injecting megawatt quantities onto the grid or injecting megawatts to withdrawing megawatts). Energy Storage Resource Model Participants or solar-storage Open-Loop Hybrid Resource operating in Continuous Mode are considered to have an unlimited ramp rate. Continuous Mode requires Discharge Economic Maximum Megawatts to be zero or correspond to an injection, and Charge Economic Maximum Megawatts to be zero or correspond to a withdrawal.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:

“Control Zone” shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:

“Controllable A.C. Merchant Transmission Facilities” shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:

“Coordinated External Transaction” shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:

“Coordinated Transaction Scheduling” or “CTS” shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:

“Corporate Guaranty” shall mean a legal document, in a form acceptable to PJM and/or PJMSettlement, used by a Credit Affiliate of an entity to guaranty the obligations of another entity.

Cost of New Entry:

“Cost of New Entry” or “CONE” shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:

As used in Tariff, Part IV, Tariff, Part VI and related attachments, “Costs” shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load.

Credit Affiliate:

"Credit Affiliate" shall mean Principals, corporations, partnerships, firms, joint ventures, associations, joint stock companies, trusts, unincorporated organizations or entities, one of which directly or indirectly controls the other or that are both under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of a person or an entity.

Credit Available for Export Transactions:

"Credit Available for Export Transactions" shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:

"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:

"Credit Breach" shall mean (a) the failure of a Participant to perform, observe, meet or comply with any requirements of Tariff, Attachment Q or other provisions of the Agreements, other than a Financial Default, or (b) a determination by PJM and notice to the Participant that a Participant represents an unreasonable credit risk to the PJM Markets; that, in either event, has not been cured or remedied after any required notice has been given and any cure period has elapsed.

Credit-Limited Offer:

"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Support Default:

"Credit Support Default," shall mean (a) the failure of any Guarantor of a Market Participant to make any payment, or to perform, observe, meet or comply with any provisions of the applicable Guaranty or Credit Support Document that has not been cured or remedied, after any required notice has been given and an opportunity to cure (if any) has elapsed, (b) a representation made or deemed made by a Guarantor in any Credit Support Document that proves to be false, incorrect or misleading in any material respect when made or deemed made, (c) the failure of a Guaranty or other Credit Support Document to be in full force and effect prior to the satisfaction of all obligations of such Participant to PJM, without PJM's consent, or (d) a Guarantor repudiating, disaffirming, disclaiming or rejecting, in whole or in part, its obligations under the Guaranty or challenging the validity of the Guaranty.

Credit Support Document:

"Credit Support Document" shall mean any agreement or instrument in any way guaranteeing or securing any or all of a Participant's obligations under the Agreements (including, without limitation, the provisions of Tariff, Attachment Q), any agreement entered into under, pursuant to, or in connection with the Agreements or any agreement entered into under, pursuant to, or in connection with the Agreements and/or any other agreement to which PJM, PJMSettlement and the Participant are parties, including, without limitation, any Corporate Guaranty, Letter of Credit, or agreement granting PJM and PJMSettlement a security interest.

Critical Natural Gas Infrastructure:

"Critical Natural Gas Infrastructure" shall mean locations with electrical loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility as defined by NERC/FERC standard(s); and until such NERC/FERC standard(s) is developed, is defined as electric loads that are involved in natural gas production, processing, intrastate and interstate transmission and distribution pipeline facility, which if curtailed, will impact the delivery of natural gas to bulk-power system natural gas-fired generation.

Cross-Border:

When used to describe Network Integration Transmission Service, Network External Designated Transmission Service or Point-to-Point Transmission Service, "Cross-Border" shall mean transmission service where the capacity and/or energy is delivered from a resource that is not part of the PJM Transmission System and/or to load that is not part of the PJM Transmission System.

CTS Enabled Interface:

“CTS Enabled Interface” shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling (“CTS”). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:

“CTS Interface Bid” shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:

“Curtailment” shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:

“Curtailment Service Provider” or “CSP” shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:

“Customer Facility” shall mean Generation Facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV.

Customer-Funded Upgrade:

“Customer-Funded Upgrade” shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:

"Customer Interconnection Facilities" shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13.

Daily Unforced Capacity Obligation:

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:

"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:

"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:

"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Settlement Interval:

"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:

"Deactivation" shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:

"Deactivation Avoidable Cost Credit" shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:

"Deactivation Avoidable Cost Rate" shall mean the formula rate established pursuant to Tariff, Part V, section 115.

Deactivation Date:

"Deactivation Date" shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:

"Decrement Bid" shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:

As used in the Interconnection Service Agreement and Construction Service Agreement, "Default" shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:

"Delivering Party" shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:

"Delivery Year" shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:

"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:

"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:

"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Designated Agent:

"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:

"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:

"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Charging Energy:

"Direct Charging Energy" shall mean the energy that an Energy Storage Resource or Open-Loop Hybrid Resource purchases from the PJM Interchange Energy Market and (i) later resells to the PJM Interchange Energy Market; or (ii) is lost to conversion inefficiencies, provided that such inefficiencies are an unavoidable component of the conversion, storage, and discharge process that is used to resell energy back to the PJM Interchange Energy Market.

Direct Load Control:

"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Discharge Economic Maximum Megawatts:

"Discharge Economic Maximum Megawatts" shall mean the maximum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Continuous Mode or in Discharge Mode. Discharge Economic Maximum Megawatts shall be the Economic Maximum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Discharge Mode or in Continuous Mode.

Discharge Economic Minimum Megawatts:

"Discharge Economic Minimum Megawatts" shall mean the minimum megawatt power output available for discharge in economic dispatch by an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Discharge Mode. Discharge Economic Minimum Megawatts shall be the Economic Minimum for an Energy Storage Resource or solar-storage Open-Loop Hybrid Resource in Discharge Mode.

Discharge Mode:

"Discharge Mode" shall mean the mode of operation of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource that only includes positive megawatt quantities (i.e., the Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource is only injecting megawatts onto the grid).

Discharge Ramp Rate:

"Discharge Ramp Rate" shall mean the Ramping Capability of an Energy Storage Resource Model Participant or solar-storage Open-Loop Hybrid Resource in Discharge Mode.

Dispatch Rate:

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dispatched Charging Energy:

"Dispatched Charging Energy" shall mean Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid pursuant to PJM dispatch while providing one of the following services in the PJM markets: Energy Imbalance Service pursuant to Tariff, Schedule 4; Regulation; Tier 2 Synchronized Reserves; or Reactive Service. Energy Storage Resource Model Participants and Open-Loop Hybrid Resource shall be considered to be providing Energy Imbalance Service when they are dispatchable by PJM in real-time.

Dynamic Schedule:

"Dynamic Schedule" shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:

"Dynamic Transfer" shall have the same meaning provided in the Operating Agreement.

Definitions – E - F

Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

"Effective FTR Holder" shall mean:

(i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:

"Electrical Distance" shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

"Eligible Customer" shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

"Eligible Fast-Start Resource" shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency Action:

"Emergency Action" shall mean (1) any megawatt shortage of the Primary Reserve Requirement (as specified in the PJM Manuals) in a Reserve Zone or Reserve Sub-zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of non-essential building loads and Voltage Reduction Warning that encompasses such Reserve Zone or Reserve Sub-zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for an entire Reserve Zone or Reserve Sub-zone.

Emergency Condition:

"Emergency Condition" shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

"Emergency Load Response Program" shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Energy Market Opportunity Cost:

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

"Energy Resource" shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

"Energy Settlement Area" shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

"Energy Storage Resource Model Participant" shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

"Energy Storage Resource Participation Model" shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

"Energy Transmission Injection Rights" shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

"Entity Providing Supply Services to Default Retail Service Provider" shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Event of Default:

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Exercise of Buyer-Side Market Power:

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

"Export Nodal Reference Price" at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

"Export Transaction" shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

"Export Transaction Price Factor" for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

"Export Transaction Screening" shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

"Export Transactions Net Activity" shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

"Extended 30-minute Reserve Requirement" shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

Facilities Study:

"Facilities Study" shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider's Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider's Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer's New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

"Fast-Start Resource" shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

"Federal Power Act" shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

"FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

"Final Offer" shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

"Financial Close" shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

"Financial Default" shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall mean Transmission Service under the Tariff, Part II, section 13 that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

"Firm Transmission Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

"Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:

"Foreign Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

"Form 715 Planning Criteria" shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

"Forward Daily Natural Gas Prices" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

"Forward Hourly Ancillary Services Prices" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

"Forward Hourly LMPs" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, ”FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

"FTR Participant" shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM's FTR market.

FTR Portfolio Auction Value:

"FTR Portfolio Auction Value" shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

"Fuel Cost Policy" shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller's method used to price fuel for calculation of the Market Seller's cost-based offers for a generation resource.

Full Notice to Proceed:

"Full Notice to Proceed" shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – L – M – N

Legacy Policy:

"Legacy Policy" shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

List of Approved Contractors:

"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

"Load Interest" shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:

"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

"Load Serving Charging Energy" shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource for later resale to end-use load.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

"LOC Deviation," shall mean, for units other than wind or solar units, Hybrid Resources, or Energy Storage Resources, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind or solar units, Hybrid Resources, or Energy Storage Resources, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output, inclusive of state of charge, for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource's bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area. Notwithstanding the foregoing, for the 2024/2025 Delivery Year, during the auction process, the Office of Interconnection shall exclude from the Locational Deliverability Area Reliability Requirement any Planned Generation Capacity Resource in an LDA that does not participate in the relevant RPM Auction as projected internal capacity and in the Capacity Emergency Transfer Objective model where the Locational Deliverability Area Reliability Requirement for the Base Residual Auction increases by more than one percent over the reliability requirement used from the prior Delivery Year's Base Residual Auction (for Incremental Auctions the Locational Deliverability Area Reliability Requirement would be compared with the reliability requirement used in the prior relevant RPM Auction associated with the same Delivery Year) for that LDA due to the cumulative addition of such Planned Generation Capacity Resources.

Locational Price Adder:

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:

"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

"Marginal Value" shall mean the incremental change in system dispatch costs, measured as a $/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

"Market Monitor**"** means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

"Market Monitoring Unit Advisory Committee" or "MMU Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

"Market Participant" shall mean a Market Buyer, a Market Seller, and/or an Economic Load Response Participant, or all three, except when that term is used in or pertaining to Tariff, Attachment M, Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-

Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4. "Market Participant," when such term is used in Tariff, Attachment M, shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale. "Market Participant," when such term is used in or pertaining to Tariff, Attachment Q, Operating Agreement, section 15, Tariff, Attachment K-Appendix, section 1.4 and Operating Agreement, Schedule 1, section 1.4, shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, an FTR Participant, a Capacity Market Buyer, or a Capacity Market Seller.

Market Participant Energy Injection:

"Market Participant Energy Injection" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

"Market Participant Energy Withdrawal" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

"Market Revenue Neutrality Offset" shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Suspension:

"Market Suspension" shall mean the inability of the Office of the Interconnection to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances, as further described in Operating Agreement, Schedule 1, section

1.10.8(d) and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.8(d), or the inability of the Office of the Interconnection to produce Zonal Dispatch Rates for a total of seven (7) or more Real-time Settlement Intervals within a clock hour, for the purposes of the Real-time Energy Market, as further described in Operating Agreement, Schedule 1, section 1.11.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.11.6.

Market Violation:

"Market Violation" shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

"Material Modification" shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

"Maximum Daily Starts" shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:

"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Down Time:

For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Exposure:

"Minimum Exposure" shall mean the greater of: (a) $3,000 and (b) one percent (1%) of the greatest amount invoiced for the Participant's transaction activity for all PJM Markets and services in any rolling one, two, or three-week period in the prior 52 weeks, rounded up to the nearest multiple of $100; provided, however, that the Minimum Exposure shall be capped at a maximum of $100,000.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero to the time of the last generator breaker opening as measured by PJM's State Estimator.

Minimum Transfer Amount:

"Minimum Transfer Amount" shall mean the greater of: (a) $20,000 and (b) five percent (5%) of the greatest amount invoiced for the Participant's transaction activity for all PJM Markets and services in any rolling one, two, or three-week period in the prior 52 weeks, rounded up to the nearest multiple of $100; provided, however, that the Minimum Transfer Amount shall be capped at a maximum of $500,000.

MISO:

"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

"Mixed Technology Facility" shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

"MOPR Floor Offer Price" shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2).

Multi-Driver Project:

"Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

"Native Load Customers" shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner's system to meet the reliable electric needs of such customers.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III. There are two types of firm Network Integration Transmission Service: Regional Network Integration Transmission Service and firm Cross-Border Network Integration Transmission Service. Non-firm Network Integration Transmission Service includes Secondary Service.

Network Load:

"Network Load" shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer's Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

"Network Operating Agreement" shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

"Network Operating Committee" shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

"Network Resource" shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

"Network Service User" shall mean an entity using Network Transmission Service.

Network Transmission Service:

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

"Neutral Party" shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

"New Entry Capacity Resource with State Subsidy" shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New PJM Zone(s):

"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

"New Services Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

"No-load Cost" shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit's no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Dispatched Charging Energy:

"Non-Dispatched Charging Energy" shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:

"Non-Performance Charge" shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

"Nonincumbent Developer" shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

"Non-Retail Behind The Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

"Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions – O – P - Q

Obligation:

"Obligation" shall mean all amounts owed to PJMSettlement for purchases from the PJM Markets, Transmission Service, (under both Tariff, Part II and Tariff, Part III), and other services or obligations pursuant to the Agreements. In addition, aggregate amounts that will be owed to PJMSettlement in the future for capacity purchases within the PJM capacity markets will be added to this figure. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Offer Data:

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the Transmission System in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C. subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Office of the Interconnection Control Center:

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

On-Site Generators:

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

Open Access Same-Time Information System (OASIS) or PJM Open Access Same-Time Information System:

"Open Access Same-Time Information System," "PJM Open Access Same-Time Information System" or "OASIS" shall mean the electronic communication and information system and standards of conduct contained in Part 37 and Part 38 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

Open-Loop Hybrid Resource:

"Open-Loop Hybrid Resource" shall mean a Hybrid Resource with a storage component that is physically and contractually capable of charging its storage component from the grid.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C., on file with the Commission.

Operating Day:

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

Operating Margin:

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

Operating Margin Customer:

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

Operating Reserve Demand Curve:

"Operating Reserve Demand Curve" shall mean a curve with prices on the y-axis and megawatts on the x-axis, which defines the relationship between each incremental megawatt of reserves that can be used to meet a given reserve requirement.

Operationally Deliverable:

"Operationally Deliverable" shall mean, as determined by the Office of the Interconnection, that there are no operational conditions, arrangements or limitations experienced or required that threaten, impair or degrade effectuation or maintenance of deliverability of capacity or energy from the external Generation Capacity Resource to loads in the PJM Region in a manner comparable to the deliverability of capacity or energy to such loads from Generation Capacity Resources located inside the metered boundaries of the PJM Region, including, without limitation, an identified need by an external Balancing Authority Area for a remedial action scheme or manual generation trip protocol, transmission facility switching arrangements that would have the effect of radializing load, or excessive or unacceptable frequency of regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability dispatch instructions and commitments.

Opportunity Cost:

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

OPSI Advisory Committee:

"OPSI Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.G.

Option to Build:

"Option to Build" shall mean the option of the New Service Customer to build certain Customer-Funded Upgrades, as set forth in, and subject to the terms of, the Construction Service Agreement.

Optional Interconnection Study:

"Optional Interconnection Study" shall mean a sensitivity analysis of an Interconnection Request based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement:

"Optional Interconnection Study Agreement" shall mean the form of agreement for preparation of an Optional Interconnection Study, as set forth in Tariff, Attachment N-3.

Part I:

"Part I" shall mean the Tariff Definitions and Common Service Provisions contained in Tariff, Part I, sections 1 through 12A.

Part II:

"Part II" shall mean Tariff, Part II, sections 13 through 27A pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part III:

"Part III" shall mean Tariff, Part III, sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part IV:

"Part IV" shall mean Tariff, Part IV, sections 36 through 112C pertaining to generation or merchant transmission interconnection to the Transmission System in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part V:

"Part V" shall mean Tariff, Part V, sections 113 through 122 pertaining to the deactivation of generating units in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Part VI:

"Part VI" shall mean Tariff, Part VI, sections 200 through 237 pertaining to the queuing, study, and agreements relating to New Service Requests, and the rights associated with Customer-Funded Upgrades in conjunction with the applicable Common Service Provisions of Tariff, Part I and appropriate Schedules and Attachments.

Participant:

"Participant" shall mean a Market Participant and/or Transmission Customer and/or Applicant requesting to be an active Market Participant and/or Transmission Customer**.**

Parties:

"Parties" shall mean the Transmission Provider, as administrator of the Tariff, and the Transmission Customer receiving service under the Tariff. PJMSettlement shall be the Counterparty to Transmission Customers.

Peak-Hour Dispatch:

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under Tariff, Attachment DD, section 5, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle), plus 10% of such costs only for the 2022/2023 Delivery Year, for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate, plus 10% of such costs only for the 2022/2023 Delivery Year, under the same conditions as described above for the Day-ahead Energy Market.

Peak Market Activity:

"Peak Market Activity" shall mean a measure of exposure for which credit is required, calculated in accordance with Tariff, Attachment Q, section VII.A.

Peak Market Activity Shortfall:

"Peak Market Activity Shortfall" shall mean, for any given week, the amount by which a Participant's current Peak Market Activity exceeds such Participant's Peak Market Activity credit requirement from the prior week.

Peak Market Activity Surplus:

"Peak Market Activity Surplus" shall mean, for any given week, the amount by which a Participant's Peak Market Activity credit requirement from the prior week exceeds such Participant's current Peak Market Activity.

Peak Season:

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

Performance Assessment Interval:

“Performance Assessment Interval” shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection.

Permissible Technological Advancement:

“Permissible Technological Advancement” shall mean a proposed technological change such as an advancement to turbines, inverters, plant supervisory controls or other similar advancements to the technology proposed in the Interconnection Request that is submitted to the Transmission Provider no later than the return of an executed Facilities Study Agreement (or, if a Facilities Study is not required, prior to the return of an executed Interconnection Service Agreement). Provided such change may not: (i) increase the capability of the Generating Facility as specified in the original Interconnection Request; (ii) represent a different fuel type from the original Interconnection Request; or (iii) cause any material adverse impact(s) on the Transmission System with regard to short circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response. If the proposed technological advancement is a Permissible Technological Advancement, no additional study will be necessary and the proposed technological advancement will not be considered a Material Modification.

PJM:

“PJM” shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Administrative Service:

“PJM Administrative Service” shall mean the services provided by PJM pursuant to Tariff, Schedule 9.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Control Area:

“PJM Control Area” shall mean the Control Area recognized by NERC as the PJM Control Area.

PJM Entities:

“PJM Entities” shall mean PJM, including the Market Monitoring Unit, the PJM Board, and PJM’s officers, employees, representatives, advisors, contractors, and consultants.

PJM Interchange:

"PJM Interchange" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds, or is exceeded by, the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller; or (e) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the inteval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Interchange Energy Market:

"PJM Interchange Energy Market" shall mean the regional competitive market administered by the Office of the Interconnection for the purchase and sale of spot electric energy at wholesale in interstate commerce and related services established pursuant to Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K – Appendix.

PJM Interchange Export:

"PJM Interchange Export" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load is exceeded by the sum of the inteval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the interval scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the interval net metered output of any other Market Seller.

PJM Interchange Import:

"PJM Interchange Import" shall mean the following, as determined in accordance with the Operating Agreement and Tariff: (a) for a Market Participant that is a Network Service User, the amount by which its interval Equivalent Load exceeds the sum of the interval outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the interval scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the interval scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

PJM Liaison:

"PJM Liaison" shall mean the liaison established under Tariff, Attachment M, section III.I.

PJM Management:

"PJM Management" shall mean the officers, executives, supervisors and employee managers of PJM.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning, and accounting requirements of the PJM Region and the PJM Interchange Energy Market.

PJM Markets:

"PJM Markets" shall mean the PJM Interchange Energy Market, capacity markets, including the RPM auctions, and any other market operated by PJM, together with all bilateral or other wholesale electric power and energy transactions, capacity transactions, ancillary services transactions (including black start service), transmission transactions, Financial Transmission Rights transactions, or transactions in any other market operated under the Agreements within the PJM Region, wherein Market Participants may incur Obligations to PJM and/or PJMSettlement.

PJM Market Rules:

"PJM Market Rules" shall mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.

PJM Net Assets:

"PJM Net Assets**"** shall mean the total assets per PJM's consolidated quarterly or year-end financial statements most recently issued as of the date of the receipt of written notice of a claim less amounts for which PJM is acting as a temporary custodian on behalf of its Members, transmission developers/Designated Entities, and generation developers, including, but not limited to, cash deposits related to credit requirement compliance, study and/or interconnection receivables, member prepayments, invoiced amounts collected from Net Buyers but have not yet been paid to Net Sellers, and excess congestion (as described in Operating Agreement, Schedule 1, section 5.2.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.6).

PJM Region:

"PJM Region" shall have the meaning specified in the Operating Agreement.

PJM Regional Practices Document:

"PJM Regional Practices Document" shall mean the document of that title that compiles and describes the practices in the PJM Markets and that is made available in hard copy and on the Internet.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to RAA, Schedule 4.1, as approved by the PJM Board.

PJM Region Peak Load Forecast:

“PJM Region Peak Load Forecast” shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in Tariff, Attachment DD, section 5.

PJM Region Reliability Requirement:

“PJM Region Reliability Requirement” shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

PJMSettlement:

“PJM Settlement” or “PJM Settlement, Inc.” shall mean PJM Settlement, Inc. (or its successor), established by PJM as set forth in Operaitng Agreement, section 3.3.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” “OATT,” or “PJM Open Access Transmission Tariff” shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Plan:

“Plan” shall mean the PJM market monitoring plan set forth in Tariff, Attachment M.

Planned Demand Resource:

“Planned Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Planned External Generation Capacity Resource:

“Planned External Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Planned Generation Capacity Resource:

“Planned Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Planning Period:

“Planning Period” shall mean the 12 moths beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Planning Period Balance:

“Planning Period Balance” shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

Planning Period Quarter:

“Planning Period Quarter” shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

Point(s) of Delivery:

“Point(s) of Delivery” shall mean the point(s) on the Transmission Provider’s Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Tariff, Part II. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point of Interconnection:

“Point of Interconnection” shall mean the point or points where the Customer Interconnection Facilities interconnect with the Transmission Owner Interconnection Facilities or the Transmission System.

Point(s) of Receipt:

“Point(s) of Receipt” shall mean point(s) of interconnection on the Transmission Provider’s Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Tariff, Part II. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

Point-To-Point Transmission Service:

“Point-To-Point Transmission Service shall mean the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Tariff, Part II.

Power Purchaser:

"Power Purchaser" shall mean the entity that is purchasing the capacity and energy to be transmitted under the Tariff.

PRD Curve:

"PRD Curve" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Provider:

"PRD Provider" shall have the meaning provided in the Reliability Assurance Agreement.

PRD Reservation Price:

"PRD Reservation" Price shall have the meaning provided in the Reliability Assurance Agreement.

PRD Substation:

"PRD Substation" shall have the meaning provided in the Reliability Assurance Agreement.

Pre-Confirmed Application:

"Pre-Confirmed Application" shall be an Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

Pre-Emergency Load Response Program:

"Pre-Emergency Load Response Program" shall be the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during pre-emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Pre-Expansion PJM Zones:

"Pre-Expansion PJM Zones" shall be zones included in the Tariff, along with applicable Schedules and Attachments, for certain Transmission Owners – Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power and Light Company, Jersey Central Power and Light Company, Mid-Atlantic Interstate Transmission, LLC ("MAIT") (MAIT owns and operates the transmission facilities in the Metropolitan Edison Company Zone and the Pennsylvania Electric Company Zone), PECO Energy Company, Pennsylvania Power & Light Group, Potomac Electric Power Company, Public Service Electric and Gas Company, Allegheny Power, and Rockland Electric Company.

Price Responsive Demand:

"Price Responsive Demand" shall have the meaning provided in the Reliability Assurance Agreement.

Primary Reserve:

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

Primary Reserve Alert

"Primary Reserve Alert" shall mean a notification from PJM to alert Members of an anticipated shortage of Operating Reserve capacity for a future critical period.

Primary Reserve Requirement:

"Primary Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Primary Reserve absent any increase to account for additional reserves scheduled to address operational uncertainty. The Primary Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve or Non-Synchronized Reserve resources.

Principal:

"Principal" shall mean (i) all natural persons who Control Corporate Level Strategy for the Participant, which shall include a chief executive officer, managing member (or equivalent positions regardless of title) and members of a board of directors or board of managers; (ii) the chief legal officer or general counsel (or equivalent position regardless of title); (iii) the natural person who Controls the financial affairs and investments of the Participant, which shall include a chief financial officer (or equivalent position regardless of title); (iv) the natural person who Controls the Participant's management of commodity and derivatives market risks, which shall include a chief risk officer (or equivalent position regardless of title); (v) the natural person who Controls the Participant's transactions in the applicable PJM Markets (regardless of title); and (vi) all Beneficial Owners.

"Control," as that term is used in this definition, refers to possession of the power to direct the management or policies of an entity.

"Corporate Level Strategy," as that term is used in this definition, refers to the highest-level strategy of an entity, focused on the entity's overall direction rather than the day-to-day operations of the entity.

"Beneficial Owner," as that term is used in this definition, means a natural person who, directly or indirectly, alone or together with such person's Family Members, owns, controls, or holds with power to vote 10 percent or more of the outstanding securities of the Participant.

"Family Member," as that term is used in this definition of "Beneficial Owner," means a spouse, domestic partner, parent, child, or sibling.

For purposes of trusts with, directly or indirectly, 10 percent or more of the outstanding securities of the Participant as described above, the following are Beneficial Owners: (a) a natural person trustee; (b) a natural person with the authority to dispose of the trust assets; (c) a natural person grantor or settlor who has the right to revoke the trust or otherwise withdraw the assets of the trust; and (d) a natural person beneficiary who is the sole permissible recipient of income and principal from the trust or has the right to demand a distribution of or withdraw substantially all of the assets from the trust.

If, due to the Participant's business enterprise, structure or otherwise, a function described in clauses (i) through (v) above is performed by a natural person or entity separate from the Participant (such as a risk management department in an affiliate, or a director or manager at an entity that controls or invests in the Participant), then for that Participant the term Principal shall mean that natural person, or the senior officer or manager of that entity, that performs such function.

Prior CIL Exception External Resource:

"Prior CIL Exception External Resource" shall mean an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in RAA, Article I or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof) is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.

Project Financing:

"Project Financing" shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Customer Facility, any alteration, expansion or improvement to the Customer Facility, the purchase and sale of the Customer Facility or the operation of the Customer Facility; (b) a power purchase agreement pursuant to which Interconnection Customer's obligations are secured by a mortgage or other lien on the Customer Facility; or (c) loans and/or debt issues secured by the Customer Facility.

Project Finance Entity:

"Project Finance Entity" shall mean: (a) a holder, trustee or agent for holders, of any component of Project Financing; or (b) any purchaser of capacity and/or energy produced by the Customer Facility to which Interconnection Customer has granted a mortgage or other lien as security for some or all of Interconnection Customer's obligations under the corresponding power purchase agreement.

Projected EAS Dispatch:

"Projected EAS Dispatch" shall mean, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource's offer and operating parameters. For combustion turbine units only, the cost-based energy offer will include a 10 percent adder only for the 2022/2023 Delivery Year.

Projected PJM Market Revenues:

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Proportional Multi-Driver Project:

"Proportional Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Provisional Interconnection Service:

"Provisional Interconnection Service" shall mean interconnection service provided by Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to Transmission Provider's Transmission System and enabling that Transmission System to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interconnection Service Agreement and, if applicable, the Tariff.

Pseudo-Tie:

"Pseudo-Tie" shall have the same meaning provided in the Operating Agreement.

Public Policy Objectives:

"Public Policy Objectives" shall have the same meaning provided in the Operating Agreement.

Public Policy Requirements:

"Public Policy Requirements" shall have the same meaning provided in the Operating Agreement.

Qualifying Transmission Upgrade:

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

Queue Position:

"Queue Position" shall mean the priority assigned to an Interconnection Request, a Completed Application, or an Upgrade Request pursuant to applicable provisions of Tariff, Part VI.

Definitions – R - S

Ramping Capability:

“Ramping Capability” shall mean the sustained rate of change of generator output, in megawatts per minute.

Rating Agency:

“Rating Agency” shall mean a Nationally Recognized Statistical Rating Organization that assesses the financial condition, strength and stability of companies and governmental entities and their ability to timely make principal and interest payments on their debts and the likelihood of default, and assigns a rating that reflects its assessment of the ability of the company or governmental entity to make the debt payments.

Real-time Congestion Price:

“Real-time Congestion Price” shall mean the Congestion Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:

“Real-time Loss Price” shall mean the Loss Price resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:

“Real-time Energy Market” shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Offer:

“Real-time Offer” shall mean a new offer or an update to a Market Seller’s existing cost-based or market-based offer for a clock hour, submitted for use after the close of the Day-ahead Energy Market.

Real-time Prices:

“Real-time Prices” shall mean the Locational Marginal Prices resulting from the Office of the Interconnection’s dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Settlement Interval:

“Real-time Settlement Interval” shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Reasonable Efforts:

"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Tariff, Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:

"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:

"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:

For Delivery Years up to and including the 2025/2026 Delivery Year, "Reference Resource" shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh. For the 2026/2027 Delivery Year and subsequent Delivery Years, "Reference Resource" shall mean a combined cycle generating station, configured with a double train 1x1 single shaft General Electric Frame 7HA.02 turbine with an F-A650 steam turbine with evaporative cooling, Selective Catalytic Reduction technology and carbon monoxide catalyst, with firm gas transportation, and a heat rate of 6.604 MMbtu/MWh (with duct firing) and 6.369 MMbtu/MWh (without duct firing).

Regional Entity:

"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Network Integration Transmission Service:

"Regional Network Integration Transmission Service" shall mean firm transmission service taken by Network Customers that involves the delivery of energy and/or capacity from Network

Resources physically interconnected to the Transmission Provider's transmission system to Network Load physically interconnected to the Transmission Provider's transmission system.

Regional Transmission Expansion Plan:

"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):

"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:

"Relevant Electric Retail Regulatory Authority" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

"Reliability Assurance Agreement" or "PJM Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:

“Reliability Pricing Model Auction” or “RPM Auction” shall mean the Base Residual Auction or any Incremental Auction.

Required Transmission Enhancements:

“Regional Transmission Enhancements” shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B (“Appendix B Agreement”) designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:

“Reserved Capacity” shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider’s Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:

“Reserve Penalty Factor” shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:

“Reserve Sub-zone” shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:

“Reserve Zone” shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:

"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource Substitution Charge:

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

Restricted Collateral:

"Restricted Collateral" shall mean Collateral, held by PJM or PJMSettlement, which cannot be used, netted, credited or spent by the Participant to satisfy any other obligations.

Revenue Data for Settlements:

"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:

"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section VI.

Scheduled Incremental Auctions:

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

Schedule of Work:

"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:

"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:

"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Reserve:

"Secondary Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes (less the capability of such resources to provide Primary Reserve), from the request of the Office of the Interconnection, regardless of whether the equipment providing the reserve is electrically synchronized to the Transmission System or not.

Secondary Systems:

"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

Security:

"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:

"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Self-Supply:

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

Self-Supply Entity:

"Self-Supply Entity" shall mean the following types of Load Serving Entity that operate under long-standing business models: single customer entity, public power entity, or vertically integrated utility, where "vertically integrated utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation or receives any cost recovery for such generation through bilateral contracts; "single customer entity" means a Load Serving Entity that serves at retail only customers that are under common control with such Load Serving Entity, where such control means holding 51% or more of the voting securities or voting interests of the Load Serving Entity and all its retail customers; and "public power entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same and rural electric cooperatives, and joint action agencies.

Self-Supply Seller:

"Self-Supply Seller" shall mean, for purposes of evaluating Buyer-Side Market Power, the following types of Load Serving Entities that operate under long-standing business models: vertically integrated utility or public power entity, where "vertically integrated utility" means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and "public power entity" means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Sell Offer:

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

Service Agreement:

"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:

"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:

"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:

"Short-term Project" shall have the same meaning provided in the Operating Agreement.

Site:

"Site" shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:

"Small Commercial Customer," as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:

"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:

"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:

"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start Fuel:

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours)

Start-Up Costs:

"Start-Up Costs" shall consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units): Start-Up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.

For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-Up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:

"State Commission" shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in a storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or a storage component of a Hybrid Resource using minimum and maximum discharge (and, as applicable, charge) limits, changes in operating mode (as applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

State Subsidy:

"State Subsidy" shall mean a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that

(1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or

(2) will support the construction, development, or operation of a new or existing Capacity Resource; or

(3) could have the effect of allowing the unit to clear in any PJM capacity auction.

Notwithstanding the foregoing, State Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Surplus Interconnection Customer:

"Surplus Interconnection Customer" shall mean either an Interconnection Customer whose Generating Facility is already interconnected to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Customer is not a New Service Customer.

Surplus Interconnection Request:

"Surplus Interconnection Request" shall mean a request submitted by a Surplus Interconnection Customer, pursuant to Tariff, Attachment RR, to utilize Surplus Interconnection Service within the Transmission System in the PJM Region. A Surplus Interconnection Request is not a New Service Request.

Surplus Interconnection Service:

"Surplus Interconnection Service" shall mean any unneeded portion of Interconnection Service established in an Interconnection Service Agreement, such that if Surplus Interconnection Service is utilized, the total amount of Interconnection Service at the Point of Interconnection would remain the same.

Switching and Tagging Rules:

"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or

Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by a directed amount of the assigned or self-scheduled Synchronized Reserve.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System Condition:

"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:

"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:

"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

Definitions – T – U - V

Tangible Net Worth:

"Tangible Net Worth" shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

Third-Party Sale:

"Third-Party Sale" shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

"Tie Line" shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost

Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

"Total Net Obligation" shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

"Total Net Sell Position" shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Trade Reference:

"Trade Reference" shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

"Transmission Constraint Penalty Factor" shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

"Transmission Customer" shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

"Transmission Facilities" shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Injection Rights:

"Transmission Injection Rights" shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

"Transmission Interconnection Customer" shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

"Transmission Interconnection Facilities Study" shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

"Transmission Interconnection Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

"Transmission Interconnection Request" shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

"Transmission Owner Attachment Facilities" shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner's side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

"Transmission Owner Interconnection Facilities" shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner's side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

"Unsecured Credit" shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

"Unsecured Credit Allowance" shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: "Working Credit Limit."

Updated VRR Curve:

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

Updated VRR Curve Decrement:

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

"Upgrade Construction Service Agreement" shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

"Upgrade Customer" shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

"Upgrade Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

"Upgrade-Related Rights" shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

"Upgrade Request" shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

"Up-to Congestion Counterflow Transaction" shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

"Up-to Congestion Historical Month" shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an "Up-to Congestion Prevailing Flow Transaction" if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

"Up-to Congestion Reference Price" for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30^{th} percentile
For Up-to Congestion Counterflow Transactions when bid: 20^{th} percentile
For Up-to Congestion Counterflow Transactions when cleared: 5^{th} percentile

Up-to Congestion Transaction:

"Up-to Congestion Transaction" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

"Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Variable Resource Requirement Curve:

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

"Virtual Credit Exposure" shall mean the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

"Virtual Transaction Screening" shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

"Virtual Transactions Net Activity" shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii)

Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

"Voltage Reduction Action" shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

"Voltage Reduction Alert" shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

"Voltage Reduction Warning" shall mean a notification from PJM to warn Members that PJM's available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

SCHEDULE 6A
Black Start Service

References to section numbers in this Schedule 6A refer to sections of this Schedule 6A, unless otherwise specified.

To ensure the reliable restoration following a shut down of the PJM transmission system, Black Start Service is necessary to facilitate the goal of complete system restoration. Black Start Service enables the Transmission Provider to designate specific generators called Black Start Units whose location and capabilities are required to re-energize the transmission system following a system-wide blackout. The Transmission Provider shall administer the provision of Black Start Service. PJMSettlement shall be the Counterparty to the purchases and sales of Black Start Service.

TRANSMISSION CUSTOMERS

1. All Transmission Customers and Network Customers must obtain Black Start Service through the Transmission Provider, with PJMSettlement as the Counterparty, pursuant to this Schedule 6A.

PROVISION OF BLACK START SERVICE

2. A Black Start Unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in the PJM manuals. The expected life of the Black Start Unit shall take into consideration expectations regarding both the enabling equipment and the generation unit itself.

A Fuel Assured Black Start Unit is a Black Start Unit that is capable of starting without an outside electrical supply and running 16 hours or more at full load and either stores at least 16 hours of fuel on site, can operate independently on 2 or more interstate pipelines, is directly connected to a natural gas gathering system or is an intermittent or hybrid resource that has been evaluated by the Transmission Provider to be capable of providing no less than 16 hours of operation per day, which need not be continuous, at a megawatt level that provides a confidence level of 90% based on an evaluation of the unit's historical operation over a representative period of time, and meets any other requirements specified in the PJM manuals. Distributed energy resources interconnected to distribution facilities may qualify as Fuel Assured Black Start Units under the criteria that applies to all Fuel Assured Black Start Units. Unless otherwise specified as only applicable to Fuel Assured Black Start Units, all terms and conditions set forth in this Tariff, Schedule 6A applicable to Black Start Units shall be deemed to include Fuel Assured Black Start Units.

3. A Black Start Plant is a generating plant that includes one or more Black Start Units. A generating plant with Black Start Units electrically separated at different voltage levels will be considered multiple Black Start Plants.

4. The Transmission Provider is responsible for developing a coordinated and efficient system restoration plan that identifies all of the locations where Black Start Units are needed. The PJM Manuals shall set forth the criteria and process for selecting or identifying the Black Start Units necessary to commit to providing Black Start Service at the identified locations. No Black Start Unit shall be eligible to recover the costs of providing Black Start Service in the PJM Region unless it agrees to provide such service for a term of commitment established under section 5, 6, or 6A below.

5. Owners of Black Start Units selected to provide Black Start Service in accordance with Schedule 6A, section 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner or the Transmission Provider provides written, one-year advance notice of its intention to terminate the commitment or the commitment is involuntarily terminated pursuant to section 15 of this Schedule 6A. Black Start Units that are selected to provide Black Start Service after June 6, 2021, pursuant to Schedule 6A, section 6 that subsequently transition from the Capital Cost Recovery Rate to the Base Formula Rate shall have a lifetime commitment and can only terminate for the reason specified in Schedule 6A, section 6(ii).

6. (i) Owners of Black Start Units selected to provide Black Start Service prior to June 6, 2021, in accordance with section 4 of this Schedule 6A and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon the age of the Black Start Unit or the longest expected life of the Incremental Black Start Capital Cost, as set forth in the applicable CRF Table in section 18 of this Schedule 6A. For those Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the applicable term of commitment as set forth in the CRF Table in section 18 of this Schedule 6A. The Transmission Provider may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Black Start Unit owner shall be eligible to recover any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice and consent of the Transmission Provider (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i) of this Schedule 6A) in excess of the amount that would have been recovered pursuant to section 18 of this Schedule 6A during the same period. At the conclusion of the term of commitment established under this section 6 of this Schedule 6A, a Black Start Unit shall commence a new term of commitment under either section 5 or 6 of this Schedule 6A, as applicable.

(ii) Owners of Black Start Units selected to provide Black Start Service after June 6, 2021, in accordance with Schedule 6A, section 4 and electing to recover new or additional Black

Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial capital recovery period based upon the age of the Black Start Unit plus the remaining life of the Black Start equipment. For those Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the initial capital recovery period based upon the age of the Black Start Unit plus the remaining life of the Black Start equipment.

(iii) Black Start Units selected to be Fuel Assured Black Start Units in accordance with Schedule 6A, section 4 and electing to recover new or additional Fuel Assurance Capital Costs or new and additional Fuel Assurance Costs and Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial capital recovery period based upon the age of the Black Start Unit plus the remaining life of the Black Start equipment. For those Fuel Assured Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the initial capital recovery period based upon the age of the Black Start Unit plus the remaining life of the Black Start equipment. For those Fuel Assured Black Start Units that elect to recover new or additional Fuel Assurance Capital Costs, the applicable capital recovery period shall be the fuel assurance capital recovery period based upon the age of the Fuel Assured Black Start Unit .

The Transmission Provider may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Black Start Unit owner shall be eligible to recover any amount of unrecovered Fixed Black Start Service Costs including any amount of unrecovered Fuel Assurance Capital Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice and consent of the Transmission Provider (or its commitment period may be involuntarily terminated pursuant to the section 15 below), provided the Black Start Unit's owner demonstrates to the satisfaction of the Transmission Provider at least one of the following reasons for such termination apply:

a. Black Start Unit retirement or deactivation with at least one year's notice;

b. Expiration of a state, federal, or other governmental agency permit(s) required for Black Start Service with at least one year's notice; or

c. Additional capital is required by the Black Start Unit owner to maintain Black Start Service capability (in which case, the Black Start Unit will apply for Black Start Service selection in accordance with the procedures set forth in Manual 12 and only continue to provide Black Start Service if selected for Black Start Service by the Transmission Provider).

Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs and/or Fuel Assurance Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i) of this Schedule 6A) in excess of the amount that would have been recovered pursuant to Schedule 6A, section 18 during the same period.

6A. Black Start Units which are owned or contracted for by a Transmission Owner to provide Black Start Service as a result of the black start reliability backstop process defined in the PJM Manuals, shall be subject to cost recovery through such Transmission Owner's annual revenue requirement under such Transmission Owner's Tariff, Attachment H, as filed with, and accepted by, FERC under Section 205 of the Federal Power Act and in accordance with Tariff, Part I, section 9, or through such other cost recovery mechanism, provided that such cost recovery mechanism is filed with and accepted by FERC. The relevant Transmission Owner shall commit to provide, or effectuate the provision of, Black Start Service from such a Black Start Unit for the FERC-approved cost recovery period. The Transmission Provider may terminate the commitment with one year advance notice of its intention to the Transmission Owner. Provision of Black Start Service from a Black Start Unit obtained through the black start reliability backstop process defined in the PJM Manuals shall be subject to sections 7 through 13 of this Schedule 6A. The Revenue Requirements, Credits, and Charges provisions contained in sections 16 through 27 of this Schedule 6A, shall not apply to Black Start Units obtained as a result of the black start reliability backstop process defined in the PJM Manuals.

6B. In the event that a Black Start Unit fails to fulfill its commitment established under section 5 to provide Black Start Service, receipt of any Black Start Service revenues associated with the non-performing Black Start Unit shall cease and, for the period of the unit's non-performance, the Black Start Unit owner shall forfeit the Black Start Service revenues associated with the non-performing Black Start Unit that it received or would have received had the Black Start Unit performed, not to exceed revenues for a maximum of one year.

In the event that a Black Start Unit fails to fulfill its commitment established under section 6 above, such unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i) of this Schedule 6A) in excess of the amount that would have been recovered pursuant to section 18 of this Schedule 6A during the same period, but such unit remains eligible to establish a new commitment under section 5 or 6 of this Schedule 6A. Provided, however, Black Start Units that are selected to provide Black Start Service after June 6, 2021, pursuant to Schedule 6A, section 6 that subsequently transition from the Capital Cost Recovery Rate to the Base Formula Rate shall have a lifetime commitment and can only terminate for a reason specified in Schedule 6A, section 6(ii).

Performance Standards and Outage Restrictions

7. In addition to the performance capabilities set forth in the PJM Manuals, Black Start Units must have the capabilities listed below. These capabilities must be demonstrated in accordance with the criteria set forth in the PJM manuals and will remain in effect for the duration of the commitment to provide Black Start Service.

a. A Black Start Unit must be able to close its output circuit breaker to a dead (de-energized) bus within the time specified in the PJM Manuals.

b. A Black Start Unit must be capable of maintaining frequency and voltage under varying load.

c. A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

d. A Fuel Assured Black Start Unit must meet the fuel assurance requirements as specified in the PJM Manuals.

8. Each owner of Black Start Units or Black Start Plants must maintain procedures for the start-up of the Black Start Units.

9. If a Black Start Unit is a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, this ability must be demonstrated in accordance with the criteria set forth in the PJM manuals.

10. No more than one Black Start Unit at a Black Start Plant may be subject to a Generator Planned Outage or Generator Maintenance Outage at any one time without written approval of the Transmission Provider and the Transmission Owner in the Zone receiving Black Start Service from the Black Start Plant. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not selected for providing Black Start Service in accordance with this Schedule 6A, section 4 and the PJM Manuals may be substituted for a Black Start Unit that is subject to a Generator Planned Outage to permit a concurrent planned outage of another critical Black Start Unit at the same Black Start Plant. The Black Start Unit used as a substitute shall not receive compensation for additional capital expenditures to qualify for Black Start Service, will not increase the current Black Start Unit capital recovery commitment period, must be connected at the same voltage level and cranking path, must be similar age as the current Black Start Unit, must provide equivalent Black Start Unit Capacity, and must have had a valid annual test within the previous 13 months. Black Start Unit substitutions may be permitted for reasons other than Generator Planned Outages if requested by the Black Start Unit owner and if approved by the Transmission Provider; provided, however, all requests for Black Start Unit substitutions must be supported by documentation and information demonstrating operational or technical reasons for the substitution satisfactory to the Transmission Provider and may only occur once within a 12-month period.

11. Concurrent planned outages at multiple Black Start Plants within a zone may be restricted based on Transmission Owner requirements for Black Start Service availability. Such restrictions must be predefined and approved by Transmission Provider in accordance with the PJM manuals.

Testing

12. To verify that they can be started and operated without being connected to the Transmission System, Black Start Units shall be tested annually in accordance with the Tariff and the PJM Manuals. Fuel Assured Black Start Units that are dual fuel must conduct an annual test on both fuels. The Black Start Unit owner shall determine the time of the annual test.

13. Compensation under this Schedule 6A for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's minimum run time at the higher of the unit's cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

14. All Black Start Units must have a successful annual test on record with the Transmission Provider within the preceding 13 months. A Black Start Unit receiving revenues under Section 5 or Section 6 above that does not have a successful annual test on record with the Transmission Provider within the preceding 13 months will not qualify to receive Black Start Service revenues. A Fuel Assured Black Start Unit that stores fuel on-site and fails in any month to store the fuel and non-fuel consumables needed to meet its fuel assurance run hour requirements except for allowable conditions specified in the PJM Manuals, and except when the Fuel Assured Black Start Unit can also operate independently on 2 or more interstate pipelines, does not qualify to receive Black Start revenues in that month.

15. If a Black Start Unit fails the annual test, the unit may be re-tested within a ten-day period without financial penalty. If the Black Start Unit does not successfully re-test within that ten-day period, monthly Black Start Service revenues under this Schedule 6A will be forfeited by that unit from the time of the first unsuccessful test until such time as the unit passes an annual test. If the Black Start Unit owner does not make the necessary repairs to enable the Black Start Unit to pass the annual test within 90 days of the due date for the annual test pursuant to section 14 above, the Black Start Unit will immediately cease to qualify as a Black Start Unit and, if applicable, will have failed to fulfill its commitment pursuant to section 5 or section 6 above, whichever is applicable, of this Schedule 6A and will be subject to the additional forfeiture of revenues set forth in section 6B of this Schedule 6A. The 90 day period may be extended up to 1 year by the Transmission Provider in accordance with the PJM Manuals. If the 90 day period is extended, the Black Start Unit owner will continue to forfeit all revenues starting in the month of the first failed test until the Black Start Unit has demonstrated to the Transmission Provider that a successful test has been completed.

Revenue Requirements

16. A Black Start Unit Owner's annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider bill for Black Start Service charges and credits.

17. Black Start Service revenue requirements for each Black Start Unit shall be based, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either section 5 or 6 of this Schedule 6A, as applicable, or (ii) the formula rates set forth in section 18 of this Schedule 6A for the commitment term set forth in section 5 or 6 of this Schedule 6A as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation.

17A. Annual Review for all Black Start Units

Requests for Black Start Service revenue requirements and for changes to the Black Start Service revenue requirements must be submitted to the Market Monitoring Unit for review and analysis, with supporting data and documentation, pursuant to Tariff, Attachment M–Appendix, section III and the PJM Manuals, with a copy to the Office of the Interconnection, by no later than May 3 of each year. The Market Monitoring Unit and the Black Start Unit owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. By no later than May 21 of each year, the Black Start Unit owner shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees or disagrees with the Market Monitoring Unit's determination of the level of each component included in the Black Start Service revenue requirements. The Black Start Unit owner may also submit Black Start Service revenue requirements that it chooses to the Office of the Interconnection by no later than May 21 of each year, provided that (i) it has participated in good faith with the process described in this section and in Tariff, Attachment M-Appendix, section III (ii) the Black Start Service revenue requirements are no higher than the level defined in any agreement reached by the Black Start Unit owner and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the Black Start Service revenue requirements are accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and PJM Manuals.

The Office of the Interconnection shall determine whether to accept the values submitted by the Black Start Unit owner subject to the requirements of the Tariff and the PJM Manuals by no later than May 27. If the Office of the Interconnection does not accept the values submitted by the Black Start Unit owner in such case, the Black Start Unit owner may file its proposed values with the Commission for approval. Pursuant to Tariff, Attachment M-Appendix, section III, if the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Unit owner to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission. The annual calculation of Black Start Service revenue requirements shall become effective on June 1 of each year, except that no change to a Black Start Service revenue requirement shall become effective until the existing revenue requirement has been effective for at least twelve months. Notwithstanding the foregoing, the deadlines set forth in this section 17 shall not apply to a Black Start Unit owner's election to select a new method of recovery for its Fixed BSSC.

17B. Initial Review for New Black Start Units or existing Black Starts Units that require Fuel Assured Capital Cost

Requests for new Black Start Service revenue requirements and/or Fuel Assured Capital Costs must be submitted to the Market Monitoring Unit for review and analysis, with supporting data and documentation, pursuant to Tariff, Attachment M–Appendix, section III and the PJM Manuals, with a copy to the Office of the Interconnection, by no later than 90 days after entering Black Start Service or qualifying to be a Fuel Assured Black Start Unit. The Market Monitoring Unit and the Black Start Unit owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements by no later than 90 days after the Black Start Unit owner's submittal of final black start capital costs (if applicable), variable black start costs, and fuel storage cost documentation. By no later than 90 days of the Black Start Unit owner's submittal of final black start cost documentation, the Market Monitoring Unit shall calculate the new Black Start Unit's annual revenue requirement and submit it to the Office of the Interconnection and the Black Start Unit owner. If more than three Black Start Unit owners submit documentation within a 90-day period, the Market Monitoring Unit shall complete the review of the first three submittals within 90 days and the next set of three within the following three months and so on until all are complete. The Black Start Unit owner shall notify the Office of the Interconnection and the Market Monitoring Unit in writing if it disagrees with the Market Monitoring Unit's determination of the level of any component included in the Black Start Service revenue requirements within 7 days after the Market Monitoring Unit's submittal of the annual revenue requirement to the Office of the Interconnection. The Black Start Unit owner shall also submit Black Start Service revenue requirements that it proposes to the Office of the Interconnection provided that (i) it has participated in good faith with the process described in this section and in Tariff, Attachment M-Appendix, section III; (ii) the Black Start Service revenue requirements are no higher than the level defined in any agreement reached by the Black Start Unit owner and the Market Monitoring Unit that resulted from the foregoing process; and (iii) the Black Start Service revenue requirements are accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and PJM Manuals.

The Office of the Interconnection shall determine whether to accept the values submitted by the Black Start Unit owner subject to the requirements of the Tariff and the PJM Manuals by no later than 30 days after its receipt of the Black Start Unit owner's written notice of a disagreement. If the Office of the Interconnection does not accept the values submitted by the Black Start Unit owner in such case, the Black Start Unit owner may file its proposed values with the Commission for approval. Pursuant to Tariff, Attachment M–Appendix, section III, if the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Unit owner to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission. The annual calculation of Black Start Service revenue requirements shall become effective the day the unit enters Black Start Service or becomes fuel assured.

18. The formula for calculating a generator's annual Black Start Service revenue requirement is:

{(Fixed BSSC) + (Variable BSSC) + (Training Costs) + (Fuel Storage Costs)} * (1 + Z)

For units that have the demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the formula is revised to:

(Training Costs) * (1+ Z)

Where:

Fixed BSSC

Black Start Units with a commitment established under section 5 of this Schedule 6A shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following Base Formula Rate:

Base Formula Rate:

Net CONE * Black Start Unit Capacity * X

Where:

"Net CONE" is the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE Area where the Black Start Unit is located.

"Black Start Unit Capacity" is either: (i) the Black Start Unit's installed capacity, expressed in MW, for those Black Start Units which are not Fuel Assured Black Start Units that are Generation Capacity Resources; (ii) the awarded MWs in the Transmission Provider's request for proposal process under the PJM Manuals, for those Black Start Units, which are not Fuel Assured Black Start Units, that are Energy Resources; (iii) the Fuel Assured Black Start Unit's installed capacity for fuel assured non-intermittent Capacity Resources; or (iv) the monthly 90% confidence MW value calculated by the Transmission Provider for fuel assured intermittent or hybrid Capacity Resources. The 90% confidence MW value is calculated using Black Start Unit historical data to determine the hourly MW value the resource can provide each day in each month for 16 hours, which need not be continuous. The hourly MW value is then iterated until the confidence level of the unit providing the MW value on a monthly basis for 16 hours is 90%.

"X" is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For non-fuel assured Black Start Units with a commitment established under Schedule 6A, X shall be .01 for Hydro units, .02 for CT units. For fuel assured Black Start Units with a commitment established under Schedule 6A, X shall be .02 for all units.

Black Start Units with a commitment established under section 6 above shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with one of the following formulas, as applicable:

Capital Cost Recovery Rate – NERC-CIP Specific Recovery

(Net Cone * Black Start NERC-CIP Unit Capacity * X) + (Incremental Black Start NERC-CIP Capital Costs * CRF) + (Fuel Assurance Capital Costs * CRF)

Where:

"Net Cone" is the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE are where the Black Start Unit is located.

"Black Start NERC-CIP Unit Capacity" is the Black Start Unit's installed capacity, expressed in MW, but, for purposes of this calculation, capped at 100 MW for Hydro units, or 50 MW for CT units.

"Incremental Black Start NERC-CIP Capital Cost" are those capital costs documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a Black Start Unit to maintain compliance with mandatory Critical Infrastructure Protection Reliability Standards (as approved by the Commission and administered by the applicable Electric Reliability Organization).

"Fuel Assurance Capital Costs" are the new or additional capital costs documented by the owner for the installation of equipment necessary for the unit to meet the fuel assurance criteria specified in the PJM manuals.

"CRF" or "Capital Recovery Factor" is equal to the levelized CRF as set forth in the applicable CRF table posted on the PJM website in accordance with Tariff, Schedule 6A, section 18 and Manual 15.

A Black Start Unit may elect to terminate forward cost recovery under this Capital Cost Recovery Rate – NERC-CIP Specific Recovery at any time and seek cost recovery under the Capital Cost Recovery Rate, pursuant to the terms and conditions set forth below.

Capital Cost Recovery Rate

(FERC-approved rate) + (Incremental Black Start Capital Costs * CRF) + (Fuel Assurance Capital Costs * CRF)

Where:

"FERC-approved rate" is the Black Start Unit's current FERC-approved recovery of costs to provide Black Start Service, if applicable. To the extent that a Black Start Unit owner is currently recovering black start costs pursuant to a FERC-approved rate, that cost recovery will be included as a formulaic component for calculating the Black Start Unit's annual revenue requirement pursuant to this section 18. However, under no circumstances will PJM or the Black Start Unit owner restructure or modify that existing FERC-approved rate without FERC approval.

"Incremental Black Start Capital Costs" are the new or additional capital costs documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Unit owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit. However, Incremental Black Start Capital Costs shall not include any capital costs that the Black Start Unit owner is recovering for that unit pursuant to a FERC-approved recovery rate.

"Fuel Assurance Capital Costs" are the new or additional capital costs documented by the owner for the installation of equipment necessary for the unit to meet the fuel assurance criteria specified in the PJM manuals. However, Fuel Assurance Capital Costs shall not include any capital costs that the Fuel Assured Black Start Unit owner is recovering for that unit pursuant to a FERC-approved recovery rate.

The Capital Recovery Factor ("CRF") is equal to the Levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service.

The CRF applicable to Black Start Capital Costs of Black Start Units selected for Black Start Service prior to June 6, 2021, shall continue to be determined in accordance with the following table:

Age of Black Start Unit	Term of Black Start Commitment	Levelized CRF
1 to 5	20	0.1180
6 to 10	15	0.1348
11 to 15	10	0.1767
16+	5	0.3097

The CRF applicable to Black Start Capital Costs and/or for Fuel Assurance Capital Costs, of Black Start Units selected for Black Start Service after June 6, 2021, shall be updated annually on March 1 (if March 1 is not a Business day then the first Business Day after March 1) for (i) federal income tax rates as utilized by the U.S. Internal Revenue Service in effect at the time of the annual CRF update; (ii) average state tax rate; and (iii) debt interest rates and shall be posted on the PJM website by March 31 each year as shown in the table below. Interested parties shall have until April 15 of each year to contest PJM's calculation of the annual CRF value before it becomes effective on June 1 of each year.

PJM determines annual CRF inputs	March 1 (if March 1 is not a Business day then the first Business Day after March 1)
PJM posts annual CRF	March 31
Deadline for contesting annual CRF	April 15
Annual revenue requirement calculation	May 3 through May 27
Annual revenue requirement with CRF in effect	June 1

The CRF values shall be calculated for a recovery period based on the age of the Black Start Unit using the equation below:

$$CRF = \frac{r\,(1+r)^N \left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\,\sum_{j=1}^{L} \frac{m_j}{(1+r)^j}\right]}{(1-s)\sqrt{1+r}\left[(1+r)^N - 1\right]} \ldots$$

Where:

Formula Symbol	Description
r	After Tax Weighted Average Cost of Capital (ATWACC), which equals (equity percentage)(cost of equity) + (debt percentage)(debt interest rate)(1 – effective tax rate)
s	Effective Tax Rate, which equals (1 – state tax rate)(federal tax rate) + state tax rate
B	Bonus depreciation percent in effect at the Black Start Unit in-service date
N	Cost recovery period based on the age of the unit in years, as established in the Age of Unit/Applicable Recovery Period table below
L	The lesser of N or 16 years
M_j	Modified Accelerated Cost Recovery System (MACRS) depreciation

The following assumptions are used in the calculation:

The current federal tax and depreciation rates are as established by U.S. Internal Revenue Service;

The state tax rate is an average of the income tax rates for all the states in the PJM Region;

The capital investment necessary to make a unit qualify for Black Start Service is made up of 50 percent equity;

The capital investment necessary to make a unit qualify for Black Start Service is made up of 50 percent debt;

The debt interest rate is based on the most recent Net CONE quadrennial review after-tax weighted average cost of capital (ATWACC) and shall be updated as follows:

The debt interest rate will be updated during the Net CONE quadrennial review; and

If the 2-year change in the Moody Utility Index for bonds rated Baa1 is more than 200 basis points, this change will be added to the interest rate used in the most recent Net CONE quadrennial review and will be used as the current year's debt interest rate.

The debt term is equal to the applicable recovery period specified in the Age of Unit/Applicable Recovery Period table below; and

The cost of equity shall be equal to an after tax internal rate of return on equity of 12%.

Any changes to the debt and equity percentages and after tax internal rate of return on equity components stated above shall be included in revisions to this section 18.

Age of the Unit (years)	Incremental Black Start Capital Costs Applicable Recovery Period (years)	Fuel Assurance Capital Costs Recovery Period (years)
1-5	20	20
6-10	15	15
11-15	10	10
16+	5	10

In those circumstances where a Black Start Unit owner has elected to recover Incremental Black Start Capital Costs and/or Fuel assurance Capital Costs, in addition to a FERC-approved recovery rate, its applicable term of commitment shall be the greater of: (i) the FERC-approved recovery period, or; (ii) the applicable term of commitment as set forth in the Age of Unit/Applicable Recovery Period table above.

After a Black Start Unit has recovered its allowable Incremental Black Start Capital Costs, Incremental Black Start NERC-CIP Capital Costs, and/or Fuel assurance Capital Costs as provided by the applicable Capital Cost Recovery Rate, and has satisfied its applicable commitment period required under section 6 of this Schedule 6A, the Black Start Unit shall be committed to providing black start in accordance with section 5 of this Schedule 6A and calculate its Fixed BSSC in accordance with the Base Formula Rate.

Variable BSSC

All Black Start Units shall calculate Variable BSSC or "Variable Black Start Service Costs" in accordance with the following formula:

Black Start Unit O&M * Y

Where:

"Black Start Unit O&M" are the operations and maintenance costs attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost Development Guidelines set forth in the PJM Manuals. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by unit.

"Y" is 0.01, unless a higher or lower value is supported by the documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start Unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost Development Guidelines in the PJM Manuals.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no variable costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

Black Start Units with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid may receive NERC compliance costs associated with providing Black Start Service in addition to the formula above, if approved in accordance with the procedures in section 17 of this Schedule 6A.

Training Costs:

All Black Start Units shall calculate Training Costs in accordance with the following formula:

50 staff hours/year/plant*75/hour

Fuel Storage Costs:

Black Start Units that store liquefied or compressed natural gas, propane, or oil on site shall calculate Fuel Storage Costs in accordance with the following formula:

{MTSL + [(# Run Hours) * (Fuel Burn Rate)]} *
(12 Month Forward Strip + Basis) * (Bond Rate)

Where:

Run Hours are the actual number of hours a Transmission Provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less.

"Fuel Burn Rate" is actual fuel burn rate for the Black Start Unit.

"12-Month Forward Strip" is the average of forward prices for the fuel burned in the Black Start Unit traded the first Business Day on or following April 1.

"Basis" is the transportation costs from the location referenced in the forward price data to the Black Start Unit plus any variable taxes.

"Bond rate" is the value determined with reference to the Moody's Utility Index for bonds rated Baa1 reported the first Business Day on or following April 1.

"MTSL" is the "minimum tank suction level" and shall apply to oil fired Black Start Units' storage tanks that have an unusable volume of oil. In the case where a Black Start Unit shares a common fuel tank, the Black Start Unit will be eligible for recovery of the Black Start Energy Tank Ratio of the MTSL in its fuel storage calculation.

Black Start Energy Tank Ratio = {(Fuel Burn Rate * Minimum Run Hours) / (Tank Capacity – MTSL)}

The MTSL fuel storage calculation shall be as follows:
{(Black Start Energy Tank Ratio * MTSL) + [(#Run Hours) * (Fuel Burn Rate)]} * (12 Month Forward Strip + Basis) * (Bond Rate)

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no associated fuel storage costs and the value for FSC shall be zero.

Z

Z shall be an incentive factor solely for Black Start Units with a commitment established under section 5 above and shall be ten percent for non-fuel assured Black Start Units and twenty percent for Fuel Assured Black Start Units. For those Black Start Units that elect to recover new or additional Black Start or Fuel Assurance Capital Costs under section 6 above, the incentive factor, Z, shall be equal to zero.

Every five years, PJM shall review the formula and its costs components set forth in this section 18, and report on the results of that review to stakeholders.

19. Transmission Provider or its agent shall have the right to independently audit the accounts and records of each Black Start Unit that is receiving payments for providing Black Start Service.

20. PJM shall notify its Members when a Black Start Unit seeks to recover new or additional Black Start NERC-CIP Capital Costs under section 18 of this Schedule 6A no later than thirty (30) days prior to the effective date of the recovery. At the written request of a PJM Member, made simultaneously to the Market Monitoring Unit and PJM, with notice to the Black Start Unit owner, the Market Monitoring Unit shall make available to the affected PJM Member for inspection at the offices of the Market Monitoring Unit, all data supporting the requested new or additional NERC-CIP specific Capital Costs. The Black Start Unit owner may elect to attend this review. In all cases, the supporting data is to be held confidential and may not be distributed.

21. The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital Costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit.

Credits

22. For existing Black Start Units, monthly credits are provided to Black Start Unit owners that submit to the Transmission Provider their annual revenue requirements established pursuant to section 17A of this Schedule 6A. The generator's monthly credit is equal to 1/12 of its annual Black Start Service revenue requirement for eligible critical Black Start Units. For new Black Start Unit owners, monthly credits will be held by the Office of the Interconnection in a non-interest bearing account until the Office of the Interconnection, or the Commission as applicable, accepts the owner's annual revenue requirement pursuant to section 17B of this Schedule 6A. New Black Start Unit owners will begin to receive monthly credits, including any monthly credits held by the Office of the Interconnection back to the date the unit enters Black Start Service and any required estimated annual revenue requirement true up after the Office of the Interconnection, or the Commission as applicable, accepts the new Black Start Unit owner's annual revenue requirement.

22A. For Fuel Assured Black Start Units that are recovering Fuel Assurance Capital Costs, pursuant to section 17B of this Schedule 6A, shall have its monthly credits reduced, but not less than zero, by the positive net value of the Day-ahead Energy Market and Real-time Energy Market revenues from being committed using the fuel assurance fuel as further described in the PJM manuals minus the cost of running on that fuel. The Black Start Unit's monthly credits shall not be increased. For Fuel Assured Black Start Units that are recovering Fuel Assurance Capital Cost and the Fuel Assurance Capital Costs increased the Installed Capacity Rating

(ICAP) of the unit, monthly credits shall be reduced, but not less than zero, by the monthly capacity revenues for the increased ICAP. Monthly credits will only be reduced during the Fuel Assurance Capital Cost recovery period.

23. Revenue requirements for jointly owned Black Start Units will be allocated to the owners based on ownership percentage.

24. Transmission Provider shall not compensate generators for Black Start Service unless they meet the Transmission Provider criteria for Black Start Service and the criteria for Black Start Service in the Applicable Standards and provide Transmission Provider with all necessary data in accordance with this Schedule 6A and the PJM manuals.

Charges

25. Zonal rates will be based on Black Start Service capability or share of generation units designated by the Transmission Provider and allocated to network service customers and point-to-point reservations. Zonal rates will include estimated annual revenue requirements for new Black Start Units from the date the units enter Black Start Service to last day of the month preceding the Office of the Interconnection's acceptance of the unit's annual revenue requirement. The estimated annual revenue requirement will be based on the Black Start Unit owner's best estimate at the time the unit enters Black Start Service. Any estimated annual revenue requirement true up will be included in the monthly bill after the Office of the Interconnection accepts the new Black Start unit's annual revenue requirement.

26. Revenue requirements for Black Start Units designated by the Transmission Provider as critical (regardless of zonal location) will be allocated to the receiving Transmission Owner's zone. Black Start Units that are shared and designated to serve multiple zones will have their annual revenues allocated by Transmission Owner designated critical load percentage.

27. Purchasers of Black Start Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner Monthly Black Start Service Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner Monthly Black Start Service Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the monthly share of Black Start Service revenue requirements for each generator nominated by the Transmission Owners in that zone.

Total Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the Zonal Generation Owner Monthly Black Start Service Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Tariff, Part I, section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of the month (not curtailed by PJM) divided by the number of hours in the day.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region on a megawatt basis, exclusive of such use by Network Customers and Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 6A.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Tariff, Attachment K-Appendix, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) below, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Tariff, Attachment K-Appendix, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy

Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market performance-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the Regulation market performance-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the Regulation market performance-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market performance-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = \mathbf{r}_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left(\left(\delta - 5\text{ Minutes}\right) / \left(5\text{ Minutes}\right)\right).$$

The Office of the Interconnection shall calculate an energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

$$\text{Error} = \text{Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the Real-time Settlement Interval accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

(l) During a Market Suspension where the suspension is less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than twenty-four (24) consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource's Regulation clearing cost is determined by the summation of their Regulation offer and opportunity cost. The opportunity cost will be based on the resource's cost-based offer and will be determined as follows:

For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.

For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation accuracy score cannot be calculated during a Market Suspension, the 100-hour rolling average accuracy score will be used for the Market Suspension period.

(ii) If the regulation mileage ratio cannot be calculated during a Market Suspension, the mileage ratio will be set to one (1) for the Market Suspension period.

(iii) If the unit-specific benefits factor cannot be calculated during a Market Suspension, the unit-specific benefits factor would be based on the historical average unit-specific benefits factor over past hours that shared the same penetration of Regulation D resources that exist for the given Market Suspension hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to Tariff, Attachment K-Appendix, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Reserve Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Operating Reserve credit shall be reduced by the greater of zero or the difference of the resource's Day-ahead Operating Reserve Target and the Balancing Operating Reserve Target, as determined below.

A resource's Day-ahead Operating Reserve Target shall be determined in accordance with the following equation:

$$(A + B) - C$$

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's Balancing Operating Reserve Target shall be determined in accordance with the following equation:

$$D – (E + F)$$

Where:

D = the sum of Start-up Costs and No-load Costs and the incremental cost of energy summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

F = the sum of all revenues earned for providing Secondary Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Tariff, Attachment K-Appendix, section 3.2.3(p) below, 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. Allocation to real-time load share under this subsection (b) shall not apply to Direct Charging Energy.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Tariff, Attachment K-Appendix, 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 ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) excluding Direct Charging Energy), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Tariff, Attachment K-Appendix, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black

Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources) costs for generation resources.

Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and less the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is reduced or suspended (or, for Energy Storage Resource Model Participants, the charging of which is increased) at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).

(ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office

of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource 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 or solar generating units, Hybrid Resource or Energy Storage Resource as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-5) If a Market Participant of an Energy Storage Resource Model Participant believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. 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 Participant 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-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

(A x B) - C

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-6)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section 3.2.3(f-4), plus any cancellation fees paid in accordance with Tariff, Attachment K-Appendix, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in section 3.2.3(q) below, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing

Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by section 3.2.3.(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Tariff, Attachment K-Appendix, 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 Tariff, Attachment K-Appendix, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Tariff, Attachment K-Appendix, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$Ramp\_Request_t = \frac{(Dispatchtarget_{t-1} - AOutput_{t-1})}{(LAtime_{t-1})}$$

$$RL\_Desired_t = AOutput_{t-1} + (Ramp\_Request_t * Case\_Eff\_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the dispatch signal and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the dispatch LMP Desired MW for each Real-time Settlement Interval.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its % off dispatch is <= 10, or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh –Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable Economic Load Response Participant 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 Tariff, Attachment K-Appendix, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. Allocation to real-time load share under this subsection (p) shall not apply to Direct Charging Energy. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, section 1.11.6, the Office of the Interconnection shall allocate the charges to the ratio share of real-time load plus export transactions.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceeds the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Tariff, Attachment K-Appendix, section 3.2.3(h)(ii)(A) to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with section 3.2.3(p). Allocation to real-time load share under this subsection (q)(i) shall not apply to Direct Charging Energy.

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Tariff, Attachment K-Appendix, section 3.2.3(q)(i). 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). Allocation to real-time load share under this subsection (q)(ii) shall not apply to Direct Charging Energy.

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under Tariff, Attachment K-Appendix, section 6.4.3, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than $2,000/MWh, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under Tariff, Attachment K-Appendix, section 6.4.3. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide.

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve

Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Market Clearing Prices exist, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Market Clearing Price to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum Synchronized Reserve Requirement shall be $2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Synchronized Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource’s energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource’s expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource’s energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource’s expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource’s unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional Condense Energy Use in excess of day-ahead Condense Energy Use in real-time multiplied by A] plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B + C + D) – (E + F + G + H)

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve the resource was directed to deploy, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. For each Real-time Settlement Interval where there is not a Synchronized Reserve Event, the megawatts that will be charged shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, or the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that was assigned or self-scheduled for Synchronized Reserve and provided more Synchronized Reserve than it was directed to deploy will be used to offset the performance of other resources that provided less assigned or self-scheduled Synchronized Reserve than they were directed to deploy during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following

January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant Resources covered by section 3.2.3A(l) below, is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced 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 an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Economic Load Response Participant Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Non-Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Non-Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Non-Synchronized Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Non-Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Non-Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Non-Synchronized Reserve Market Clearing Prices exist, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the Non-Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning Non-Synchronized Reserves.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum Primary Reserve Requirement shall be $2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Primary Reserve are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Secondary Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Market Clearing Prices exist, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary Reserve Market Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum 30-minute Reserve Requirement shall be $2000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response

Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional Condense Energy Use in excess of day-ahead Condense Energy Use multiplied by A plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero.

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve

MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

$(A + B) – (C + D + E + F)$

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

(a) Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet reliability requirements in light of supply and demand uncertainties. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with subsection (b) and the PJM Manuals.

(b) Methodology for Establishing Operating Reserve Demand Curves

For each three-month season, Winter (December through February), Spring (March through May), Summer (June through August), and Fall (September through November), and for each time-of-day block set forth in the PJM Manuals, the Office of the Interconnection shall establish Operating Reserve Demand Curves for each Reserve Zone or Reserve Sub-zone as follows:

(i) Each Operating Reserve Demand Curve shall be plotted on a graph on which megawatts of reserve is on the x-axis and price is on the y-axis;

(ii) The Operating Reserve Demand Curve for each Reserve Zone or Reserve Sub-zone shall be plotted by combining (i) a straight horizontal line starting from point (1) on the y-axis to point (2), (ii) a straight vertical line connecting points (2) and (3), and (iv) a curved line from point (3) to the x-axis, where:

(A) Point (1) is the point on the y-axis(price) equal to the Reserve Penalty Factor for the minimum reserve requirement for the subject reserve requirement (i.e., the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement, or the Minimum Synchronized Reserve Requirement);

(B) Point (2) has the y-axis coordinate of point (1) and the x-axis coordinate of the applicable minimum reserve requirement as determined for the Reserve Zone or Reserve Sub-zone in accordance with the PJM Manuals;

(C) Point (3) has the x-axis coordinate of the applicable minimum reserve requirement and the y-axis coordinate resulting from multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring an infinitesimal amount of additional MW of reserves beyond the minimum reserve requirement; and

(D) From point (3) to the x-axis, first, the Office of the Interconnection develops a curve starting at point (3). The shape of the curve will be determined by multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring each additional MW of reserves beyond the minimum reserve requirement until the resulting product falls below $0.01/MWh at which point the curve will intersect with the x-axis. These probabilities are calculated from an empirical distribution of data from a rolling three-calendar year period of the following supply and demand uncertainties, using a 30-minute time horizon for clearing Primary Reserves and Synchronized Reserves and a 60-minute time horizon for clearing 30-minute Reserves: load forecast error, wind forecast error, solar forecast error, and forced outages of thermal units, and, for the Operating Reserve Demand Curves for 30-minute Reserves only, net interchange forecast error, all as described in the PJM Manuals. The empirical distribution also accounts for the Regulation requirement, expressed in effective megawatts, that PJM has established for each hour within that time-of-day block, by reducing the magnitude of the above uncertainties by the requirement.

The Office of the Interconnection will post each Operating Reserve Demand Curve used to clear reserve markets.

(c) Annual Update of Operating Reserve Demand Curves

On an annual basis, the Office of the Interconnection shall update the determination of the probability of falling below the applicable minimum reserve requirement, including each uncertainty, to account for the most recent calendar year's data, in accordance with the PJM Manuals, and post revised Operating Reserve Demand Curves by April 1. The revised Operating Reserve Demand Curves shall become effective June 1, coincident with the start of the next Delivery Year.

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 a steam-electric generating unit, an Energy Storage Resource Model Participant, a Hybrid Resource, or a combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output (or the level of Energy Storage Resource Model Participant charging withdrawals) requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level (or the level of Energy

Storage Resource Model Participant charging withdrawals) if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from a steam-electric generating unit, an Energy Storage Resource Model Participant, a Hybrid Resource, a combined cycle unit, or a combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of 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 Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) 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 Tariff, Attachment K-Appendix, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Tariff, Attachment K-Appendix, section 5.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus sum of the applicable Reserve Penalty Factors for the Synchronized Reserved Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules.

(a) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on cost-based offers, which are always parameter limited. Such offers must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such cost-based offers ("parameter limited schedules") shall be considered in the commitment of a resource when the Market Seller does not pass the three pivotal supplier test, as further described in Operating Agreement, Schedule 1, section 6.4.1 and the parallel provisions in Tariff, Attachment K-Appendix, section 6.4.1.

(b) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on market-based offers conforming to parameter limitations ("parameter limited schedules"). Such market-based parameter limited schedules must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such market-based parameter limited schedules shall be considered in the commitment of a resource under the following circumstances:

(i) For Capacity Performance Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert, Hot Weather Alert, Cold Weather Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert for all, or any part, of an Operating Day.

(c) For Capacity Performance Resources, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual unit on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts;

(vi) Maximum Run Time;

(vii) Start-up Time; and

(viii) Notification Time.

These unit-specific values shall apply for the generating unit unless it is operating pursuant to an exception from those values under subsection (i) hereof due to operational limitations that prevent the unit from meeting the minimum parameters. Throughout the analysis process, the Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's unit-specific parameter limited schedule values.

In order to make its determination of the unit-specific parameter limited schedule values for a unit, the Office of the Interconnection may request that the Capacity Market Seller provide to it and the Market Monitoring Unit certain data and documentation as further detailed in the PJM Manuals. Once the Office of the Interconnection has made a determination of the unit-specific parameter limited schedule values for a unit, those values will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed based on changed operational capabilities of the unit.

A Capacity Market Seller that does not believe its generating unit can meet the unit-specific values determined by the Office of the Interconnection due to actual operating constraints, and who desires to establish adjusted unit-specific parameters for those units may request adjusted unit-specific parameter limitations. Any such request must be submitted to the Office of the Interconnection by no later than the February 28 immediately preceding the first Delivery Year for which the adjusted unit-specific parameters are requested to commence. Capacity Market Sellers shall supply, for each generating unit, technical information about the operational limits to support the requested parameters, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's request for adjusted unit-specific parameter limited schedule values. After it has completed its evaluation of the request, the Office of the Interconnection shall notify the Capacity Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied, by no later than April 15. The effective date of the request, if approved by the Office of the Interconnection, shall be no earlier than June 1.

The operational limitations referenced in this section 6.6 shall be (a) physical operational limitations based on the operating design characteristics of the unit, or (b) other actual physical constraints, including those based on contractual limits, that are not based on the characteristics of the unit. In order for a contractual or other actual constraint to be deemed a physical constraint that can be reflected in its unit-specific parameter limits for a Generation Capacity Resource, the Capacity Market Seller must demonstrate that contractual or other actual constraint is not simply an economic decision but a physical restriction that could not be rectified among any commercial alternatives actually available to it.

(d) [Reserved]

(e) [Reserved]

(f) [Reserved]

(g) The following additional parameter limits shall apply for Capacity Performance Resources, other than Capacity Storage Resources, submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Capacity Performance Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) The combined start-up and notification times shall not exceed 24 hours, except when a Hot Weather Alert or Cold Weather Alert has been issued;

(ii) When a Hot Weather Alert or Cold Weather Alert has been issued, combined start-up and notification times shall not exceed 14 hours;

(iii) When a Hot Weather Alert or Cold Weather Alert has been issued, notification time shall not exceed one hour; and,

(iv) When a Hot Weather Alert or Cold Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Capacity Performance Resource for both its market-based schedules and cost-based schedules.

Capacity Storage Resources that clear in a Reliability Pricing Model Auction shall, unless the Capacity Market Seller has requested for its Capacity Storage Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and notification time, and/or minimum down time, due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) Have combined start-up and notification times that shall not exceed one hour; and,

(ii) Have a minimum down time that shall not exceed one hour.

(h) [Reserved]

(i) If a generating unit is or will become unable to achieve the default or unit-specific values determined by the Office of the Interconnection due to actual operating constraints affecting the unit, the Capacity Market Seller of that unit may submit a written request for an exception to the application of those values. Exceptions to the parameter limited schedule default or unit-specific values shall be categorized as either a one-time temporary exception, lasting 30 days or less; a period exception, lasting at least 31 days and no more than one year; or a persistent exception, lasting for at least one year.

(i) Temporary Exceptions. A temporary exception shall be deemed accepted without prior review by the Market Monitoring Unit or the Office of the Interconnection upon submission by the Market Seller of the generating unit of written notification to the Market Monitoring Unit and the Office of the Interconnection, and shall automatically commence and terminate on the dates specified in such notification, which must be for a period of time lasting 30 days or less, unless the termination date is extended pending a request for a period exception or shortened due to a change in the physical conditions of the unit such that the temporary exception is no longer required. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection within three days following the commencement of the temporary exception its documentation explaining in detail the reasons for the temporary exception, and shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Failure to provide a timely response to such request for additional information shall cause the temporary exception to terminate the following day. The Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing of any updates to the physical condition of the unit and shall notify the Office of Interconnection and the Market Monitoring Unit in writing of an early termination of a temporary exception due to changed physical conditions by no later than one Business Day prior to the early termination date. A Market Seller shall provide supporting documentation demonstrating the actual termination date of the physical and actual parameter limitation that prompted the need for the temporary exception to the Office of Interconnection and the Market Monitoring Unit within one Business Day of the termination of such condition. A temporary exception may only be requested one-time for the same physical and actual constraint per occurrence since an operational constraint that may periodically exist more than once should be the subject of a period exception request rather than multiple temporary exception requests.

In addition, if a Market Seller is unaware of the need for a period exception prior to the February 28 deadline for submitting such requests, the Market Seller may utilize the temporary exception process and seek to modify that exception pursuant to the process described below.

Modification of Temporary Exceptions. If, prior to the scheduled termination date the Market Seller determines that the temporary exception must persist for more than 30 days and the Market Seller wants to extend the period for which the exception applies, or if a Market Seller is unaware of the need for a period or persistent exception prior to the February 28 deadline for submitting such requests and the Market Seller has submitted a temporary exception request, it must submit to the Market Monitoring Unit and the Office of the Interconnection a written request to modify the temporary exception to become a period exception or a persistent exception, and provide detailed documentation explaining the reasons for the requested modification of the temporary exception. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period or persistent exception request, and if the exception requested is based on new physical operating limits for the unit for which some or all historical operating data is unavailable, the Market Seller may also submit technical information about the physical operational limits of the unit to support the requested parameters. Such Market Seller shall respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Such request shall be reviewed by the Market Monitoring Unit and must be evaluated by the Office of the Interconnection using the same standard utilized to evaluate period exception and persistent exception requests. Per Tariff, Attachment M-Appendix, section II.B, the Market Monitoring Unit shall evaluate the modification request and provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request. The Office of the Interconnection shall provide its determination whether the request complies with the Tariff and Manuals by no later than 20 Business Days from the date of the modification request. A temporary exception shall be extended and shall not terminate until the date on which the Office of the Interconnection issues its determination of the modification request.

(ii) Period Exceptions and Persistent Exceptions. Market Sellers must submit period exception and persistent exception requests to the Market Monitoring Unit and the Office of the Interconnection by no later than the February 28 immediately preceding the twelve month period from June 1 to May 31 during which the exception is requested to commence. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period exception or persistent exception request, and if the exception requested is based on new physical operational limits for the unit for which some or all historical operating data is unavailable, the generating unit may also submit technical information about the physical operational limits for exceptions of the unit to support the requested parameters. The Market Monitoring Unit shall evaluate such request in accordance with the process set forth in Tariff, Attachment M-Appendix, section II.B. A Market Seller (i) must submit a parameter limited schedule value consistent with an agreement with the Market Monitoring Unit under such process or (ii) if it has not agreed with the Market Monitoring Unit on the parameter limited schedule value, may submit its own value to the Office of the Interconnection and to the Market Monitoring Unit, by no later than April 8. Each exception request must indicate the expected duration of the requested exception including the termination date thereof. The proposed parameter limited schedule value submitted by the Market Seller is subject to approval of the Office of the Interconnection pursuant to the requirements of the Tariff and the PJM Manuals. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the exception request. After it has completed its evaluation of the exception request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the exception request is approved or denied, by no later than April 15. The effective date of the exception, if approved by the Office of the Interconnection, shall be no earlier than June 1 of the applicable Delivery Year. The Office of the Interconnection's determination for an exception shall continue for the period requested and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

The Market Seller shall provide written notification to the Market Monitoring Unit and the Office of the Interconnection of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection in their evaluations of the Market Seller's request for a period or persistent exception. The Market Monitoring Unit shall provide written notification to the Office of the Interconnection and the Market Seller of any change to its determination regarding the exception request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice. The Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, of any change to its determination regarding the exception request, based on the material change in facts, by no later than 20 Business Days after receipt of the Market Seller's notice. If the Office of the Interconnection determines that the exception no longer complies with the Tariff or Manuals, the following parameter values shall apply to all megawatts of the generating unit offered into the PJM energy markets:

(1) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply.

(2) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource and for which adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource adjusted unit-specific values shall apply.

(i) Notwithstanding the foregoing, the provisions of this section 6.6 shall only pertain to the Offer Data a Market Seller must submit to the Office of the Interconnection for its offers into the Day-ahead Energy Market, rebidding period that occurs after the clearing of the Day-ahead Energy Market and Real-time Energy Market, and do not affect or change in any way a Generation Owner's obligation under NERC Reliability Standards to notify the Office of the Interconnection of its actual or expected actual physical operating conditions during the Operating Day.

(k) Notwithstanding anything contrary herein, the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for a generating unit shall be applicable to that generating unit regardless whether there is a change in the owner, operator or Market Seller of the unit because the parameter limited schedule values for the unit are determined based on the physical limitations of the unit, which should not change merely based on a change in owners, operator or Market Seller. Because parameter limited schedule values attach to the generating unit and are not owned by a Market Seller of the unit, when there are multiple owners or Market Sellers for a generating unit, all owners and Market Sellers shall be bound by the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for the unit.

(l) The provisions of this section 6.6 only apply to Generation Capacity Resources, and not to Energy Resources.

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data

or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Operating Agreement, section 18.17.

B. <u>Required Disclosure</u>:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Tariff, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the Market Monitoring Unit using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the Market Monitoring Unit from a third party which is not, to the Office of the Interconnection's or Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. <u>Disclosure to FERC and CFTC</u>:

1. Notwithstanding anything in this section I to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC") or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in section I.B.

D. <u>Disclosure to Authorized Commissions</u>:

1. Notwithstanding anything in this section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member

is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member’s confidential information to any other Member.

(iii) Notwithstanding section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit’s receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a “fast track” complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. [Reserved]

II. <u>DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION</u>

A. <u>Offer Price Caps</u>:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Operating Agreement, Schedule 1, section 6.4.2and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost-based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Operating Agreement, Schedule 2.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated

under Operating Agreement, Schedule 1, section 6.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2 is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Operating Agreement, Schedule 1, section 6.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. <u>Minimum Generator Operating Parameters</u>:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Operating Agreement, Schedule 1, section 6.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6 and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Tariff, Attachment M.

C. <u>RPM Must-Offer Requirement</u>:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Tariff, Attachment DD, section 6.6.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under Tariff, Attachment DD.

3. Through the 2024/2025 Delivery Year, the Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Tariff, Attachment DD, section 6.6(b). If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORd to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Tariff, Attachment DD, section 5.6.6, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in section II.C.4 above, or (iii) through the

2024/2025 Delivery Year, a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level determined under section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Tariff, Attachment DD, section 6.6.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Tariff, Attachment DD, section 6.6(g), to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Tariff, Attachment DD, section 6.6(i), and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

D. Unit Specific Minimum Sell Offers:

1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, section 5.14(h-2), the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.

2. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

E. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Tariff, Attachment DD, section 6.7(d), the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller

Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

F. <u>Mitigation of Offers from Planned Generation Capacity Resources</u>:

Pursuant to Tariff, Attachment DD, section 6.5, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

G. <u>Data Submission</u>:

Pursuant to Tariff, Attachment DD, section 6.7, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. <u>Determination of Default Avoidable Cost Rates</u>:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Tariff, Attachment DD, section 6.7(c) and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Tariff, Attachment DD, section 6.7, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit-specific Avoidable Cost Rate are delineated in Tariff, Attachment DD, section 6.7(d).

I. **<u>Determination of PJM Market Revenues</u>:**

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Tariff, Attachment DD, section 6.8(d), and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

J. **<u>Determination of Opportunity Costs</u>:**

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Tariff, Attachment DD, section 6.7(d)(ii). The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. **<u>BLACKSTART SERVICE</u>**

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Tariff, Schedule 6A and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. **<u>DEACTIVATION RATES</u>**

1. Upon receipt of a notice to deactivate a generating unit under Tariff, Part V from the Office of the Interconnection forwarded pursuant to Tariff, Part V, section 113.1, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (or, if applicable, its designated agent) if a market power issue has been identified. The Market Monitoring Unit shall provide such notice by the following date: (a) May 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between January 1 and March 31; (b) August 31 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between April 1 and June 30; (c) November 30 of the current calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between July 1 and September 30; or (d) February 28 of the following calendar year, if the Transmission Provider received the notice required pursuant to Tariff, Part V, section 113.1 between October 1 and December 31. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Tariff, Part V, section 114 and Tariff, Part V, section 119.

V. <u>OPPORTUNITY COST CALCULATION</u>

The Market Monitoring Unit shall review requests for opportunity cost compensation under Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.
3B(h), discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the paralelle provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.3B9H).

VI. <u>FTR FORFEITURE RULE</u>

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Operating Agreement, Schedule 1, section 5.2.1(b) and Tariff, Attachment K-Appendix, section 5.2.1(b), including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Tariff, Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

ATTACHMENT Q

CREDIT RISK MANAGEMENT POLICY

I. INTRODUCTION

It is the policy of PJM that prior to an entity participating in any PJM Markets or in order to take Transmission Service, the entity must demonstrate its ability to meet the requirements in this Attachment Q. This Attachment Q also sets forth PJM's authority to deny, reject, or terminate a Participant's right to participate in any PJM Markets in order to protect the PJM Markets and PJM Members from unreasonable credit risk from any Participant's activities. Given the interconnectedness and overlapping of their responsibilities, PJM Interconnection, L.L.C. and PJM Settlement, Inc. are referred to both individually and collectively herein as "PJM."

PURPOSE

PJMSettlement is the counterparty to transactions in the PJM Markets. As a consequence, if a Participant defaults on its obligations under this Attachment Q, or PJM determines a Participant represents unreasonable credit risk to the PJM Markets, and the Participant does not post Collateral, additional Collateral or Restricted Collateral in response to a Collateral Call, the result is that the Participant represents unsecured credit risk to the PJM Markets. For this reason, PJM must have the authority to monitor and manage credit risk on an ongoing basis, and to act promptly to mitigate or reduce any unsecured credit risk, in order to protect the PJM Markets and PJM Members from losses.

This Attachment Q describes requirements for: (1) eligibility to be a Market Participant, (2) establishment and maintenance of credit by Market Participants, and (3) collateral requirements and forms of credit support that will be deemed as acceptable to mitigate risk to any PJM Markets.

This Attachment Q also sets forth (1) PJM's authority to monitor and manage credit risk that a Participant may represent to the PJM Markets and/or PJM membership in general, (2) the basis for establishing limits that will be imposed on a Market Participant in order to minimize risk, and (3) various obligations and requirements the violation of which will result in an Event of Default pursuant to this Attachment Q and the Agreements.

Attachment Q describes the types of data and information PJM will review in order to determine whether an Applicant or Market Participant presents an unreasonable risk to any PJM Markets and/or PJM membership in general, and the steps PJM may take in order to address that risk.

APPLICABILITY

This Attachment Q applies to all Applicants and Market Participants who take Transmission Service under this Tariff, or participate in any PJM Markets or market activities under the Agreements. Notwithstanding anything to the contrary in this Attachment Q, simply taking transmission service or procuring Ancillary Services via market-based rates does not imply market participation for purposes of applicability of this Attachment Q.

II. RISK EVALUATION PROCESS

PJM will conduct a risk evaluation to determine eligibility to become and/or remain a Market Participant or Guarantor that: (1) assesses the entity's financial strength, risk profile, creditworthiness, and other relevant factors; (2) determines an Unsecured Credit Allowance, if appropriate; (3) determines appropriate levels of Collateral; and (4) evaluates any Credit Support, including Guaranties or Letters of Credit.

A. Initial Risk Evaluation

PJM will perform an initial risk evaluation of each Applicant and/or its Guarantor. As part of the initial risk evaluation, PJM will consider certain Minimum Participation Requirements, assign an Internal Risk Score, establish an Unsecured Credit Allowance if appropriate, and make a determination regarding required levels of Collateral, creditworthiness, credit support, Restricted Collateral and other assurances for participation in certain PJM Markets.

Each Applicant and/or its Guarantor must provide the information set forth below at the time of its initial application pursuant to this Attachment Q and on an ongoing basis in order to remain eligible to participate in any PJM Markets. The same quantitative and qualitative factors will be used to evaluate Participants whether or not they have rated debt.

1. Rating Agency Reports

PJM will review Rating Agency reports from Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other Nationally Recognized Statistical Rating Organization for each Applicant and/or Guarantor. The review will focus on the Applicant's or its Guarantor's senior unsecured debt ratings. If senior unsecured debt ratings are not available, PJM may consider other ratings, including issuer ratings, corporate ratings and/or an implied rating based on an internally derived Internal Credit Score pursuant to section II.A.3 below.

2. Financial Statements and Related Information

Each Applicant and/or its Guarantor must submit, or cause to be submitted, audited financial statements, except as otherwise indicated below, prepared in accordance with United States Generally Accepted Accounting Principles ("US GAAP") or any other format acceptable to PJM for the three (3) fiscal years most recently ended, or the period of existence of the Applicant and/or its Guarantor, if shorter. Applicants and/or their Guarantors must submit, or cause to be submitted, financial statements, which may be unaudited, for each completed fiscal quarter of the current fiscal year. All audited financial statements provided by the Applicant and/or its Guarantor must be audited by an Independent Auditor.

The information should include, but not be limited to, the following:

(a) If the Applicant and/or its Guarantor has publicly traded securities:

(i) Annual reports on Form 10-K, together with any amendments thereto;

(ii) Quarterly reports on Form 10-Q, together with any amendments thereto;

(iii) Form 8-K reports, if any, that have been filed since the most recent Form 10-K;

(iv) A summary provided by the Principal responsible, or to be responsible, for PJM Market activity of: (1) the Participant's primary purpose(s) of activity or anticipated activity in the PJM Markets (investment, trading or "hedging or mitigating commercial risks," as such phrase has meaning in the CFTC's regulations regarding the end-user exception to clearing); (2) the experience of the Participant (and its Principals) in managing risks in similar markets, including other organized RTO/ISO markets or on regulated commodity exchanges; and (3) a high level overview of the Participant's intended participation in the PJM Markets.

(v) All audited financial statements provided by an Applicant with publicly traded securities and/or its Guarantor with publicly traded securities must be audited by an Independent Auditor that satisfies the requirements set forth in the Sarbanes-Oxley Act of 2002.

(b) If the Applicant and/or its Guarantor does not have publicly-traded securities:

(i) Annual Audited Financial Statements or equivalent independently audited financials, and quarterly financial statements, generally found on:
- Balance Sheets
- Income Statements
- Statements of Cash Flows
- Statements of Stockholder's or Member's Equity or Net Worth;

(ii) Notes to Annual Audited Financial Statements, and notes to quarterly financial statements if any, including disclosures of any material changes from the last report;

(iii) Disclosure equivalent to a Management's Discussion & Analysis, including an executive overview of operating results and outlook, and compliance with debt covenants and indentures, and off balance sheet arrangements, if any;

(iv) Auditor's Report with an unqualified opinion or written letter from auditor containing the opinion whether the annual audited financial statements comply with the US GAAP or any other format acceptable to PJM; and

(v) A summary provided by the Principal responsible or to be responsible for PJM Market activity of: (1) the Participant's primary purpose(s) of activity or anticipated activity in the PJM Markets (investment, trading or "hedging or mitigating commercial risks," as such phrase has meaning in the CFTC's regulations regarding the end-user exception to clearing); (2) the experience of the Participant (and its Principals) in managing risks in similar markets, including other organized RTO/ISO markets or on regulated commodity exchanges; and (3) a high level overview of the Participant's intended participation in the PJM Markets.

(c) If Applicant and/or Guarantor is newly formed, does not yet have three (3) years of audited financials, or does not routinely prepare audited financial statements, PJM may specify other information to allow it to assess the entity's creditworthiness, including but not limited to:

(i) Equivalent financial information traditionally found in:
- Balance Sheets
- Income Statements
- Statements of Cash Flows

(ii) Disclosure equivalent to a Management's Discussion & Analysis, including an executive overview of operating results and outlook, and compliance with debt covenants and indentures, and off balance sheet arrangements, if any; and

(iii) A summary provided by the Principal responsible or to be responsible for PJM Market activity of: (1) the Participant's primary purpose(s) of activity or anticipated activity in the PJM Markets (investment, trading or "hedging or mitigating commercial risks," as such phrase has meaning in the CFTC's regulations regarding the end-user exception to clearing); (2) the experience of the Participant (and its Principals) in managing risks in similar markets, including other organized RTO/ISO markets or on regulated commodity exchanges; and (3) a high level overview of the Participant's intended participation in the PJM Markets.

(d) During a two year transition period from June 1, 2020 to May 31, 2022, the Applicant or Guarantor may provide a combination of audited financial statements and/or equivalent financial information.

If any of the above information in this section II.A.2 is available on the internet, the Applicant and/or its Guarantor may provide a letter stating where such statements can be located and retrieved by PJM. If an Applicant and/or its Guarantor files Form 10-K, Form 10-Q, or Form 8-K with the SEC, then the Applicant and/or its Guarantor will be deemed to have satisfied the requirement by indicating to PJM where the information in this section II.A.2 can be located on the internet.

If the Applicant and/or its Guarantor fails, for any reason, to provide the information required above in this section II.A.2, PJM has the right to (1) request Collateral and/or Restricted Collateral to cover the amount of risk reasonably associated with the Applicant and/or its Guarantor's expected activity in any PJM Markets, and/or (2) restrict the Applicant from participating in certain PJM Markets, including but not limited to restricting the positions the Applicant (once it becomes a Market Participant) takes in the market.

For certain Applicants and/or their Guarantors, some of the above submittals may not be applicable and alternate requirements for compliant submittals may be specified by PJM. In the credit evaluation of Municipalities and Cooperatives, PJM may also request additional information as part of the initial and ongoing review process and will consider other qualitative factors in determining financial strength and creditworthiness.

3. Credit Rating and Internal Credit Score

PJM will use credit risk scoring methodologies as a tool in determining an Unsecured Credit Allowance for each Applicant and/or its Guarantor. As its source for calculating the Unsecured Credit Allowance, PJM will rely on the ratings from a Rating Agency, if any, on the Applicant's or Guarantor's senior unsecured debt or their issuer ratings or corporate ratings if senior unsecured debt ratings are not available. If there is a split rating between the Rating Agencies, the lower of the ratings shall apply. If no external credit rating is available PJM will utilize its Internal Credit Score in order to calculate the Unsecured Credit Allowance.

The model used to develop the Internal Credit Score will be quantitative, based on financial data found in the income statement, balance sheet, and cash flow statement, and it will be qualitative based on relevant factors that may be internal or external to a particular Applicant and/or its Guarantor.

PJM will employ a framework, as outlined in Tables 1-5 below, based on metrics internal to the Applicant and/or its Guarantor, including capital and leverage, cash flow coverage of fixed obligations, liquidity, profitability, and other qualitative factors. The particular metrics and scoring rules differ according to the Applicant's or Guarantor's line of business and the PJM Markets in which it anticipates participating, in order to account for varying sources and degrees of risk to the PJM Markets and PJM members.

The formulation of each metric will be consistently applied to all Applicants and Guarantors across industries with slight variations based on identifiable differences in entity type, anticipated market activity, and risks to the PJM Markets and PJM members. In instances where the external credit rating is used to calculate the unsecured credit allowance, PJM may also use the Internal Credit Score as an input into determining the overall risk profile of an Applicant and/or its Guarantor.

Table 1. ***Quantitative Metrics by Line of Business: Leverage and Capital Structure***	**Investor-Owned Utilities**	**Municipal Utilities**	**Co-Operative Utilities**	**Power Transmission**	**Merchant Power**	**Project Developers**	**Exploration & Production**	**Financial Institutions**	**Commodity Trading**	**Private Equity**
Debt / Total Capitalization (%)	●	●	●	●	○	○	●		●	●
FFO / Debt (%)	○	○	●	○	●	●	○		●	
Debt / EBITDA (x)	○	○	○	○	●	●	○		●	
Debt / Property, Plant & Equipment (%)	○	○	○	○						
Retained Earnings / Total Assets (%)	●	●		●			●			
Debt / Avg Daily Production or KwH ($)	○	○	○	○			●			
Tangible Net Worth ($)						○		●	○	○
Core Capital / Total Assets (%)								●		
Risk-Based Capital / RWA (%)								●		
Tier 1 Capital / RWA (%)								●		
Equity / Investments (%)										●
Debt / Investments (%)										●

● *primary metric* ○ *secondary metric* *FFO = Funds From Operations* *RWA = Risk-Weighted Asserts*

Table 2. ***Quantitative Metrics by Line of Business: Fixed Charge Coverage and Funding***	**Investor-Owned**	**Municipal Utilities**	**Co-Operativ**	**Power Transmissi**	**Merchant Power**	**Project Developers**	**Exploration & Production**	**Financial Institutions**	**Commodity Trading**	**Private Equity**
EBIT / Interest Expense (x)	●	●	●	●	●	●	●		●	●
EBITDA / Interest Expense (x)	●	●	○	●	●	●	●			
EBITDA / [Interest Exp + CPLTD] (x)	○	○	●	○	○	○	○			
[FFO + Interest Exp] / Interest Exp (x)	○	○	●	○	○	○	○			
Loans / Total Deposits (%)								●		
NPL / Gross Loans (%)								●		
NPL / [Net Worth + LLR] (%)								●		
Market Funding / Tangible Bank Assets (%)								●		

● *primary metric* ○ *secondary metric* *CPLTD = Current Portion of Long-Term Debt EBIT = Earnings Before Interest and Taxes EBITDA = Earnings Before Interest, Taxes, Depreciation and Amortization LLR = Loan Loss Reserves NPL = Non-Performing Loans*

Table 3. Quantitative Metrics by Line of Business: Liquidity	Investor-Owned Utilities	Municipal Utilities	Co-Operative Utilities	Power Transmission	Merchant	Project Developers	Exploration &	Financial Institutions	Commodity Trading	Private Equity
CFFO / Total Debt (x)										
Current Assets / Current Liabilities (x)										
Liquid Assets / Tangible Bank Assets (%)										
Sources / Uses of Funds (x)										
Weighted Avg Maturity of Debt (yrs)										
Floating Rate Debt / Total Debt (%)										

primary metric *secondary metric* *CFFO = Cash Flow From Operations*

Table 4. Quantitative Metrics by Line of Business: Profitability	Investor-Owned Utilities	Municipal Utilities	Co-Operative Utilities	Power Transmission	Merchant	Project Developers	Exploration &	Financial Institutions	Commodity Trading	Private Equity
Return on Assets (%)										
Return on Equity (%)										
Profit Volatility (%)										
Return on Revenue (%)										
Net Income / Tangible Assets (%)										
Net Profit ($)										
Net Income / Dividends (x)										

primary metric *secondary metric*

Table 5. Qualitative Factors: Industry Level	**Sample Reference Metrics**	**Investor-Owned Utilities**	**Municipal Utilities**	**Co-Operative Utilities**	**Power Transmission**	**Merchant Power**	**Project Developers**	**Exploration & Production**	**Financial Institutions**	**Commodity Trading**	**Private Equity**
Need for PJM Markets to Achieve Business Goals	Rating Agency criteria or other industry analysis	High	High	High	High	Med	Low	Med	Low	Low	N/A

Ability to Grow/Enter Markets other than PJM	Rating Agency criteria or other industry analysis	Very Low	Very Low	Very Low	Very Low	High	High	Med	Med	High	N/A
Other Participants' Ability to Serve Customers	Rating Agency criteria or other industry analysis	Low	Low	Low	Low	Low	Med	Low	Low	High	N/A
Regulation of Participant's Business	RRA regulatory climate scores, S&P BICRA	PUCS	Govt	N/A	FERC PUCs	N/A	N/A	N/A	N/A	N/A	N/A
Primary Purpose of PJM Activity	Investment ("Inv.")/ Trading ("Trade")/ Hedging or Mitigating Commercial Risk of Operations ("CRH")	CRH	CRH	CRH	CRH / Trade	CRH / Trade	CRH / Trade	CRH/ Trade	Inv./ Trade	Inv./ Trade	Inv./ Trade

RRA = Regulatory Research Associates, a division of S&P Global, Inc.   *BICRA = Bank Industry Country Risk Assessment*

The scores developed will range from 1-6, with the following mappings:

1 = Very Low Risk (S&P/Fitch: AAA to AA-; Moody's: Aaa to Aa3)
2 = Low Risk (S&P/Fitch: A+ to BBB+; Moody's: A1 to Baa1)
3 = Low to Medium Risk (S&P/Fitch: BBB; Moody's: Baa2)
4 = Medium Risk (S&P/Fitch: BBB-; Moody's: Baa3)
5 = Medium to High Risk (S&P/Fitch: BB+ to BB; Moody's Ba1 to Ba2)
6 = High Risk (S&P/Fitch: BB- and below; Moody's: Ba3 and below)

4. Trade References

If deemed necessary by PJM, whether because the Applicant is newly or recently formed or for any other reason, each Applicant and/or its Guarantor shall provide at least one (1) bank reference and three (3) Trade References to provide PJM with evidence of Applicant's understanding of the markets in which the Applicant is seeking to participate and the Applicant's experience and ability to manage risk. PJM may contact the bank references and Trade References provided by the Applicant to verify their business experience with the Applicant.

5. Litigation and Contingencies

Unless prohibited by law, each Applicant and Guarantor is also required to disclose and provide information as to the occurrence of, within the five (5) years prior to the submission of the information to PJM (i) any litigation, arbitration, investigation (formal inquiry initiated by a governmental or regulatory entity), or proceeding, pending or, to the knowledge of the involving, Applicant or its Guarantor or any of their Principals that would likely have a material adverse impact on its financial condition and/or would likely materially affect the risk of non-payment by the Applicant or Guarantor, or (ii) any finding of material defalcation, market manipulation or fraud by or involving the Applicant, Guarantor, or any of their Principals, predecessors, subsidiaries, or Credit Affiliates that participate in any United States power markets based upon a final adjudication of regulatory and/or legal proceedings, (iii) any bankruptcy declarations or petitions by or against an Applicant and/or Guarantor, or (iv) any violation by any of the foregoing of any federal or state regulations or laws regarding energy commodities, U.S. Commodity Futures Trading Commission ("CFTC") or FERC requirements, the rules of any exchange monitored by the National Futures Association, any self-regulatory organization or any other governing, regulatory, or standards body responsible for regulating activity in North American markets for electricity, natural gas or electricity-related commodity products. Each Applicant and Guarantor shall take reasonable measures to obtain permission to disclose information related to a non-public investigation. These disclosures shall be made by Applicant and Guarantor upon application, and within ten (10) Business Days of any material change with respect to any of the above matters.

6. History of Defaults in Energy Projects

Each Applicant and Guarantor shall disclose their current default status and default history for any energy related generation or transmission project (e.g. generation, solar, development), and within any wholesale or retail energy market, including but not limited to within PJM, any Independent System Operator or Regional Transmission Organization, and exchange that has not been cured within the past five (5) years. Defaults of a non-recourse project financed entity may not be included in the default history.

7. Other Disclosures and Additional Information

Each Applicant and Guarantor is required to disclose any Credit Affiliates that are currently Members of PJM, applying for membership with PJM, Transmission Customers, Participants, applying to become Market Participants, or that participate directly or indirectly in any PJM Markets or any other North American markets for electricity, natural gas or electricity-related commodity products. Each Applicant and Guarantor shall also provide a copy of its limited liability company agreement or equivalent agreement, certification of formation, articles of incorporation or other similar organization document, offering memo or equivalent, the names of its Principals, and information pertaining to any non-compliance with debt covenants and indentures.

Applicants shall provide PJM the credit application referenced in section III.A and any other information or documentation reasonably required for PJM to perform the initial risk evaluation of Applicant's or Guarantor's creditworthiness and ability to comply with the requirements contained in the Agreements related to settlements, billing, credit requirements, and other financial matters.

B. Supplemental Risk Evaluation Process

As described in section VI below, PJM will conduct a supplemental risk evaluation process for Applicants, Participants, and Guarantors applying to conduct virtual and export transactions or participate in any PJM Markets.

C. Unsecured Credit Allowance

A Market Participant may request that PJM consider it for an Unsecured Credit Allowance pursuant to the provisions herein. Notwithstanding the foregoing, an FTR Participant shall not be considered for an Unsecured Credit Allowance for participation in the FTR markets.

1. Unsecured Credit Allowance Evaluation

PJM will perform a credit evaluation on each Participant that has requested an Unsecured Credit Allowance, both initially and at least annually thereafter. PJM shall determine the amount of Unsecured Credit Allowance, if any, that can be provided to the Market Participant in accordance with the creditworthiness and other requirements set forth in this Attachment Q. In completing the credit evaluation, PJM will consider:

(a) Rating Agency Reports

PJM will review Rating Agency reports as for each Market Participant on the same basis as described in section II.A.1 above and section II.E.1 below.

(b) Financial Statements and Related Information

All financial statements and related information considered for an Unsecured Credit Allowance must satisfy all of the same requirements described in section II.A.2 above and section II.E.2 below.

2. Material Adverse Changes

Each Market Participant is responsible for informing PJM, in writing, of any Material Adverse Change in its financial condition (or the financial condition of its Guarantor) since the date of the Market Participant or Guarantor's most recent annual financial statements provided to PJM, pursuant to the requirements reflected in section II.A.2 above and section II.E.3 below.

In the event that PJM determines that a Material Adverse Change in the financial condition of a Market Participant warrants a requirement to provide Collateral, additional Collateral or Restricted Collateral, PJM shall comply with the process and requirements described in section II.A above and section II.E below.

3. Other Disclosures

Each Market Participant desiring an Unsecured Credit Allowance is required to make the disclosures and upon the same requirements reflected in section II.A.7 above and section II.E.7 below.

D. Determination of Unreasonable Credit Risk

Unreasonable credit risk shall be determined by the likelihood that an Applicant will default on a financial obligation arising from its participation in any PJM Markets. Indicators of potentially unreasonable credit risk include, but are not limited to, a history of market manipulation based upon a final adjudication of regulatory and/or legal proceedings, a history of financial defaults, a history of bankruptcy or insolvency within the past five (5) years, or a combination of current market and financial risk factors such as low capitalization, a reasonably likely future material financial liability, a low Internal Credit Score (derived pursuant to section II.A.3 above) and/or a low externally derived credit score. PJM's determination will be based on, but not limited to, information and material provided to PJM during its initial risk evaluation process, information and material provided to PJM in the Officer's Certification, and/or information gleaned by PJM from public and non-public sources.

If PJM determines that an Applicant poses an unreasonable credit risk to the PJM Markets, PJM may require Collateral, additional Collateral, or Restricted Collateral commensurate with the Applicant's risk of financial default, reject an application, and/or limit or deny Applicant's participation in the PJM Markets, to the extent and for the time period it determines is necessary to mitigate the unreasonable credit risk to the PJM Markets. PJM will reject an application if it determines that Collateral, additional Collateral, or Restricted Collateral cannot address the risk.

PJM will communicate its concerns regarding whether the Applicant presents an unreasonable credit risk, if any, in writing to the Applicant and attempt to better understand the circumstances surrounding that Applicant's financial and credit position before making its determination. In the event PJM determines that an Applicant presents an unreasonable credit risk that warrants a requirement to provide Collateral of any type, or some action to mitigate risk, PJM shall provide the Applicant with a written explanation of why such determination was made.

E. Ongoing Risk Evaluation

In addition to the initial risk evaluation set forth in sections II.A through II.D above and the annual certification requirements set forth in section III.A below, each Market Participant and/or its Guarantor has an ongoing obligation to provide PJM with the information required in section IV.A described in more detail below. PJM may also review public information regarding a Market Participant and/or its Guarantor as part of its ongoing risk evaluation. If appropriate, PJM will revise the Market Participant's Unsecured Credit Allowance and/or change its determination of creditworthiness, credit support, Restricted Collateral, required Collateral or other assurances pursuant to PJM's ongoing risk evaluation process.

Each Market Participant and/or its Guarantor must provide the information set forth below on an ongoing basis in order to remain eligible to participate in any PJM Markets. The same quantitative and qualitative factors will be used to evaluate Market Participants whether or not they have rated debt.

1. Rating Agency Reports

PJM will review Rating Agency reports for each Market Participant and/or Guarantor on the same basis as described in section II.A.1 above.

2. Financial Statements and Related Information

On an ongoing basis, Market Participants and/or their Guarantors shall provide the information they are required to provide as described in section II.A.2 above, pursuant to the schedule reflected below, with one exception. With regard to the summary that is required to be provided by the Principal responsible for PJM Market activity, with respect to experience of the Participant or its Principals in managing risks in similar markets, the Principal only needs to provide that information for a new Principal that was not serving in the position when the prior summary was provided. PJM will review financial statements and related information for each Market Participant and/or Guarantor on the same basis as described in section II.A.2 above.

Each Market Participant and/or its Guarantor must submit, or cause to be submitted, annual audited financial statements, except as otherwise indicated below, prepared in accordance with US GAAP or any other format acceptable to PJM for the fiscal year most recently ended within ten (10) calendar days of the financial statements becoming available and no later than one hundred twenty (120) calendar days after its fiscal year end. Market Participants and/or their Guarantors must submit, or cause to be submitted, financial statements, which may be unaudited, for each completed fiscal quarter of the current fiscal year, promptly upon their issuance, but no later than sixty (60) calendar days after the end of each fiscal quarter. All audited financial statements provided by the Market Participant and/or its Guarantor must be audited by an Independent Auditor.

Notwithstanding the foregoing, PJM may upon request, grant a Market Participant or Guarantor an extension of time, if the financials are not available within the time frame stated above.

3. Material Adverse Changes

Each Market Participant and each Guarantor is responsible for informing PJM, in writing, of any Material Adverse Change in its or its Guarantor's financial condition within five (5) Business Days of any Principal becoming aware of the occurrence of a Material Adverse Change since the date of the Market Participant or Guarantor's most recent annual financial statements provided to PJM. However, PJM may also independently establish from available information that a

Participant and/or its Guarantor has experienced a Material Adverse Change in its financial condition without regard to whether such Market Participant or Guarantor has informed PJM of the same.

For the purposes of this Attachment Q, a Material Adverse Change in financial condition may include, but is not be limited to, any of the following:

(a) a bankruptcy filing;
(b) insolvency;
(c) a significant decrease in market capitalization;
(d) restatement of prior financial statements unless required due to regulatory changes;
(e) the resignation or removal of a Principal unless there is a new Principal appointed or expected to be appointed, a transition plan in place pending the appointment of a new Principal, or a planned restructuring of such roles;
(f) the filing of a lawsuit or initiation of an arbitration, investigation, or other proceeding that would likely have a material adverse effect on any current or future financial results or financial condition or increase the likelihood of non-payment;
(g) a material financial default in any other organized energy, ancillary service, financial transmission rights and/or capacity markets including but not limited to those of another Regional Transmission Organization or Independent System Operator, or on any commodity exchange, futures exchange or clearing house, that has not been cured or remedied after any required notice has been given and any cure period has elapsed;
(h) a revocation of a license or other authority by any Federal or State regulatory agency; where such license or authority is necessary or important to the Participant's continued business, for example, FERC market-based rate authority, or State license to serve retail load;
(i) a significant change in credit default swap spreads, market capitalization, or other market-based risk measurement criteria, such as a recent increase in Moody's KMV Expected Default Frequency (EDF^{tm}) that is materially greater than the increase in its peers' EDF^{tm} rates, or a collateral default swap (CDS) premium normally associated with an entity rated lower than investment grade;
(j) a confirmed, undisputed material financial default in a bilateral arrangement with another Participant or counterparty that has not been cured or remedied after any required notice has been given and any cure period has elapsed;
(k) the sale by a Participant of all or substantially all of its bilateral position(s) in the PJM Markets;
(l) any adverse changes in financial condition which, individually, or in the aggregate, are material; and,
(m) any adverse changes, events or occurrences which, individually or in the aggregate, could affect the ability of the entity to pay its debts as they become due or could reasonably be expected to have a material adverse effect on any current or future financial results or financial condition.

Upon identification of a Material Adverse Change, PJM shall evaluate the financial strength and risk profile of the Market Participant and/or its Guarantor at that time and may do so on a more frequent basis going forward. If the result of such evaluation identifies unreasonable credit risk to any PJM Market as further described in section II.E.8 below, PJM will take steps to mitigate the financial exposure to the PJM Markets. These steps include, but are not limited to requiring the Market Participant and/or each Guarantor to provide Collateral, additional Collateral or additional Restricted Collateral that is commensurate with the amount of risk in which the Market Participant wants to engage, and/or limiting the Market Participant's ability to participate in any PJM Market to the extent, and for the time-period necessary to mitigate the unreasonable credit risk. In the event PJM determines that a Material Adverse Change in the financial condition or risk profile of a Market Participant and/or Guarantor, warrants a requirement to provide Collateral of any type, or some action to mitigate risk, PJM shall provide the Market Participant and/or Guarantor, a written explanation of why such determination was made. Conversely, in the event PJM determines there has been an improvement in the financial condition or risk profile of a Market Participant and/or Guarantor such that the amount of Collateral needed for that Market Participant and/or Guarantor can be reduced, PJM shall provide a written explanation why such determination was made, including the amount of the Collateral reduction and indicating when and how the reduction will be made.

4. Litigation and Contingencies

Each Market Participant and/or Guarantor is required to disclose and provide information regarding litigation and contingencies as outlined in section II.A.5 above.

5. History of Defaults in Energy Projects

Each Market Participant and/or Guarantor is required to disclose current default status and default history as outlined in section II.A.6 above.

6. Internal Credit Score

As part of its ongoing risk evaluation, PJM will use credit risk scoring methodologies as a tool in determining an Internal Credit Score for each Market Participant and/or Guarantor, utilizing the same model and framework outlined in section II.A.3 above.

7. Other Disclosures and Additional Information

Each Market Participant and/or Guarantor is required to make other disclosures and provide additional information outlined in section II.A.7 above.

PJM will monitor each Market Participant's use of services and associated financial obligations on a regular basis to determine their total potential financial exposure and for credit monitoring purposes, and may require the Market Participant and/or Guarantor to provide additional information, pursuant to the terms and provisions described herein.

Market Participants shall provide PJM, upon request, any information or documentation reasonably required for PJM to monitor and evaluate a Market Participant's creditworthiness and compliance with the Agreements related to settlements, billing, credit requirements, and other financial matters.

8. Unreasonable Credit Risk

If PJM has reasonable grounds to believe that a Market Participant and/or its Guarantor poses an unreasonable credit risk to any PJM Markets, PJM may immediately notify the Market Participant of such unreasonable credit risk and (1) issue a Collateral Call to demand Collateral, additional Collateral, or Restricted Collateral or other assurances commensurate with the Market Participant's and/or its Guarantor's risk of financial default or other risk posed by the Market Participant's or Guarantor's financial condition or risk profile to the PJM Markets and PJM members, or (2) limit or suspend the Market Participant's participation in any PJM Markets, to the extent and for such time period PJM determines is necessary to mitigate the unreasonable credit risk to any PJM Markets. PJM will only limit or suspend a Market Participant's market participation if Collateral, additional Collateral or Restricted Collateral cannot address the unreasonable credit risk.

PJM's determination will be based on, but not limited to, information and material provided to PJM during its ongoing risk evaluation process or in the Officer's Certification, and/or information gleaned by PJM from public and non-public sources. PJM will communicate its concerns, if any, in writing to the Market Participant and attempt to better understand the circumstances surrounding the Market Participant's financial and credit position before making its determination. At PJM's request or upon its own initiative, the Market Participant or its Guarantor may provide supplemental information to PJM that would allow PJM to consider reducing the additional Collateral requested or reducing the severity of limitations or other restrictions designed to mitigate the Market Participant's credit risk. Such information shall include, but not be limited to: (i) the Market Participant's estimated exposure, (ii) explanations for any recent change in the Market Participant's market activity, (iii) any relevant new load or unit outage information; or (iv) any default or supply contract expiration, termination or suspension.

The Market Participant shall have five (5) Business Days to respond to PJM's request for supplemental information. If the requested information is provided in full to PJM's satisfaction during said period, the additional Collateral requirement shall reflect the Market Participant's anticipated exposure based on the information provided. Notwithstanding the foregoing, any additional Collateral requested by PJM in a Collateral Call must be provided by the Market Participant within the applicable cure period.

In the event PJM determines that an Market Participant and/or its Guarantor presents an unreasonable credit risk, as described above, that warrants a requirement to provide Collateral of any type, or some action to mitigate risk, PJM shall provide the Market Participant with a written explanation of why such final determination was made.

PJM has the right at any time to modify any Unsecured Credit Allowance and/or require additional Collateral as may be deemed reasonably necessary to support current or anticipated market activity as set forth in Tariff, Attachment Q, sections II.A.2 and II.C.1.b. Failure to remit the required amount of additional Collateral within the applicable cure period shall constitute an Event of Default.

F. Collateral and Credit Restrictions

PJM may establish certain restrictions on available credit by requiring that some amounts of credit, i.e. Restricted Collateral, may not be available to satisfy credit requirements. Such designations shall be construed to be applicable to the calculation of credit requirements only, and shall not restrict PJM's ability to apply such designated credit to any obligation(s) in case of a default. Any such Restricted Collateral will be held by PJM, as applicable. Such Restricted Collateral will not be returned to the Participant until PJM has determined that the risk for which such Restricted Collateral is being held has subsided or been resolved.

PJM may post on PJM's web site, and may reference on OASIS, a supplementary document which contains additional business practices (such as algorithms for credit scoring) that are not included in this Attachment Q. Changes to the supplementary document will be subject to stakeholder review and comment prior to implementation. PJM may specify a required compliance date, not less than fifteen (15) calendar days from notification, by which time all Participants and their Guarantors must comply with provisions that have been revised in the supplementary document.

PJM will regularly post each Participant's and/or its Guarantor's credit requirements and credit provisions on the PJM web site in a secure, password-protected location. Each Participant and/or its Guarantor is responsible for monitoring such information, and maintaining sufficient credit to satisfy the credit requirements described herein. Failure to maintain credit sufficient to satisfy the credit requirements of the Attachment Q shall constitute a Credit Breach, and the Participant will be subject to the remedies established herein and in any of the Agreements.

G. Unsecured Credit Allowance Calculation

The external rating from a Rating Agency will be used as the source for calculating the Unsecured Credit Allowance, unless no external credit rating is available in which case PJM will utilize its Internal Credit Score for such purposes. If there is a split rating between the Rating Agencies, the lower of the ratings shall apply.

Where two or more entities, including Participants, are considered Credit Affiliates, Unsecured Credit Allowances will be established for each individual Participant, subject to an aggregate maximum amount for all Credit Affiliates as provided for in Attachment Q, section II.G.3.

In its credit evaluation of Municipalities and Cooperatives, PJM may request additional information as part of the ongoing risk evaluation process and will also consider qualitative factors in determining financial strength and creditworthiness.

1. Credit Rating and Internal Credit Score

As previously described in section II.A.3 above, PJM will determine the Internal Credit Score for an Applicant, Market Participant and/or its Guarantor using the credit risk scoring methodologies contained therein. Internal Credit Scores, ranging from 1-6, for each Applicant, Market Participant and/or its Guarantor, will be determined with the following mappings:

1 = Very Low Risk (S&P/Fitch: AAA to AA-; Moody's: Aaa to Aa3)
2 = Low Risk (S&P/Fitch: A+ to BBB+; Moody's: A1 to Baa1)
3 = Low to Medium Risk (S&P/Fitch: BBB; Moody's: Baa2)
4 = Medium Risk (S&P/Fitch: BBB-; Moody's: Baa3)
5 = Medium to High Risk (S&P/Fitch: BB+ to BB; Moody's Ba1 to Ba2)
6 = High Risk (S&P/Fitch: BB- and below; Moody's: Ba3 and below)

In instances where the external credit rating is used to calculate the unsecured credit allowance, PJM may also use the Internal Credit Score as an input into its determination of the overall risk profile of an Applicant and/or its Guarantor

2. Unsecured Credit Allowance

PJM will determine a Participant's Unsecured Credit Allowance based on its external rating or its Internal Credit Score, as applicable, and the parameters in the table below. The maximum Unsecured Credit Allowance is the lower of:

(a) A percentage of the Participant's Tangible Net Worth, as stated in the table below, with the percentage based on the Participant's external rating or Internal Credit Score, as applicable; and

(b) A dollar cap based on the external rating or Internal Credit Score, as applicable, as stated in the table below:

Internal Credit Score	Risk Ranking	Tangible Net Worth Factor	Maximum Unsecured Credit Allowance ($ Million)
1.00 – 1.99	1 – Very Low (AAA to AA-)	Up to 10.00%	$50
2.00 – 2.99	2 – Low (A+ to BBB+)	Up to 8.00%	$42
3.00 – 3.49	3 – Low to Medium (BBB)	Up to 6.00%	$33
3.50 – 4.49	4 – Medium (BBB-)	Up to 5.00%	$7
4.50 – 5.49	5 – Medium to High (BB+ to BB)	0%	$0
> 5.49	6 – High (BB- and below)	0%	$0

If a Corporate Guaranty is utilized to establish an Unsecured Credit Allowance for a Participant, the value of a Corporate Guaranty will be the lesser of:

(a) The limit imposed in the Corporate Guaranty;

(b) The Unsecured Credit Allowance calculated for the Guarantor; and

(c) A portion of the Unsecured Credit Allowance calculated for the Guarantor in the case of Credit Affiliates.

PJM has the right at any time to modify any Unsecured Credit Allowance and/or require additional Collateral as may be deemed reasonably necessary to support current market activity. Failure to remit the required amount of additional Collateral within the applicable cure period shall be deemed an Event of Default.

PJM will maintain a posting of each Participant's Unsecured Credit Allowance, along with certain other credit related parameters, on the PJM website in a secure, password-protected location. Each Participant will be responsible for monitoring such information and recognizing changes that may occur.

3. Unsecured Credit Limits For Credit Affiliates

If two or more Participants are Credit Affiliates and have requested an Unsecured Credit Allowance, PJM will consider the overall creditworthiness of the Credit Affiliates when determining the Unsecured Credit Allowances in order not to establish more Unsecured Credit for the Credit Affiliates collectively than the overall corporate family could support.

> **Example:** Participants A and B each have a $10.0 million Corporate Guaranty from their common parent, a holding company with an Unsecured Credit Allowance calculation of $12.0 million. PJM may limit the Unsecured Credit Allowance for each Participant to $6.0 million, so the total Unsecured Credit Allowance does not exceed the corporate family total of $12.0 million.

PJM will work with the Credit Affiliates to allocate the total Unsecured Credit Allowance among the Credit Affiliates while assuring that no individual Participant, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. The aggregate Unsecured Credit for a Participant, including Unsecured Credit Allowance granted based on its own creditworthiness and risk profile, and any Unsecured Credit Allowance conveyed through a Guaranty shall not exceed $50 million. The aggregate Unsecured Credit for a Credit Affiliate~~s~~ corporate family shall not exceed $50 million. A Credit Affiliate corporate family subject to this cap shall request PJM to allocate the maximum Unsecured Credit amongst the corporate family, assuring that no individual Participant or common guarantor, shall exceed the Unsecured Credit level appropriate for its credit strength and activity.

H. Contesting an Unsecured Credit Evaluation

PJM will provide to a Participant, upon request, a written explanation for any determination of or change in Unsecured Credit or credit requirement within ten (10) Business Days of receiving such request.

If a Participant believes that either its level of Unsecured Credit or its credit requirement has been incorrectly determined, according to this Attachment Q, then the Participant may send a request for reconsideration in writing to PJM. Such a request should include:

(1) A citation to the applicable section(s) of this Attachment Q along with an explanation of how the respective provisions of this Attachment Q were not carried out in the determination as made; and

(2) A calculation of what the Participant believes should be the appropriate Unsecured Credit or Collateral requirement, according to terms of this Attachment Q.

PJM will provide a written response as promptly as practical, but no more than ten (10) Business Days after receipt of the request. If the Participant still feels that the determination is incorrect, then the Participant may contest that determination. Such contest should be in written form, addressed to PJM, and should contain:

(1) A complete copy of the Participant's earlier request for reconsideration, including citations and calculations;

(2) A copy of PJM's written response to its request for reconsideration; and

(3) An explanation of why it believes that the determination still does not comply with this Attachment Q.

PJM will investigate and will respond to the Participant with a final determination on the matter as promptly as practical, but no more than twenty (20) Business Days after receipt of the request.

Neither requesting reconsideration nor contesting the determination following such request shall relieve or delay Participant's responsibility to comply with all provisions of this Attachment Q, including without limitation posting Collateral, additional Collateral or Restricted Collateral in response to a Collateral Call.

If a Corporate Guaranty is being utilized to establish credit for a Participant, the Guarantor will be evaluated and the Unsecured Credit Allowance granted, if any, based on the financial strength and creditworthiness, and risk profile of the Guarantor. Any utilization of a Corporate Guaranty will only be applicable to non-FTR credit requirements, and will not be applicable to cover FTR credit requirements.

PJM will identify any necessary Collateral requirements and establish a Working Credit Limit for each Participant. Any Unsecured Credit Allowance will only be applicable to non-FTR credit requirements, for positions in PJM Markets other than the FTR market, because all FTR credit requirements must be satisfied by posting Collateral.

III. MINIMUM PARTICIPATION REQUIREMENTS

A Participant seeking to participate in any PJM Markets shall submit to PJM any information or documentation reasonably required for PJM to evaluate its experience and resources. If PJM determines, based on its review of the relevant information and after consultation with the Participant, that the Participant's participation in any PJM Markets presents an unreasonable credit risk, PJM may reject the Participant's application to become a Market Participant, notwithstanding applicant's ability to meet other minimum participation criteria, registration requirements and creditworthiness requirements.

A. Annual Certification

Before they are eligible to transact in any PJM Market, all Applicants shall provide to PJM (i) an executed copy of a credit application and (ii) a copy of the annual certification set forth in Attachment Q, Appendix 1. As a condition to continued eligibility to transact in any PJM Market, Market Participants shall provide to PJM the annual certification set forth in Attachment Q, Appendix 1.

After the initial submission, the annual certification must be submitted each calendar year by all Market Participants between January 1 and April 30. PJM will accept such certifications as a matter of course and the Market Participants will not need further notice from PJM before commencing or maintaining their eligibility to participate in any PJM Markets.

A Market Participant that fails to provide its annual certification by April 30 shall be ineligible to transact in any PJM Markets and PJM will disable the Market Participant's access to any PJM Markets until such time as PJM receives the certification. In addition, failure to provide an executed annual certification in a form acceptable to PJM and by the specified deadlines may result in a default under the Tariff.

Market Participants acknowledge and understand that the annual certification constitutes a representation upon which PJM will rely. Such representation is additionally made under the Tariff, filed with and accepted by FERC, and any false, misleading or incomplete statement knowingly made by the Market Participant and that is material to the Market Participant's ability to perform may be considered a violation of the Tariff and subject the Market Participant to action by FERC. Failure to comply with any of the criteria or requirements listed herein or in the certification may result in suspension or limitation of a Market Participant's transaction rights in any PJM Markets.

Applicants and Market Participants shall submit to PJM, upon request, any information or documentation reasonably and/or legally required to confirm Applicant's or Market Participant's compliance with the Agreements and the annual certification.

B. PJM Market Participation Eligibility Requirements

PJM may conduct periodic verification to confirm that Applicants and Market Participants can demonstrate that they meet the definition of "appropriate person" to further ensure minimum criteria are in place. Such demonstration will consist of the submission of evidence and an executed Annual Officer Certification form as set forth in Attachment Q, Appendix 1 in a form acceptable to PJM. If an Applicant or Market Participant does not provide sufficient evidence for verification to PJM within five (5) Business Days of written request, then such Applicant or Market Participant may result in a default under this Tariff. Demonstration of "appropriate person" status and support of other certifications on the annual certification is one part of the Minimum Participation Requirements for any PJM Markets and does not obviate the need to meet the other Minimum Participation Requirements such as those for minimum capitalization and risk profile as set forth in this Attachment Q.

To be eligible to transact in any PJM Markets, an Applicant or Participant must demonstrate in accordance with the Risk Management and Verification processes set forth below that it qualifies in one of the following ways:

1. an "appropriate person," as that term is defined under Commodity Exchange Act, section 4(c)(3), or successor provision, or;

2. an "eligible contract participant," as that term is defined in Commodity Exchange Act, section 1a(18), or successor provision, or;

3. a business entity or person who is in the business of: (1) generating, transmitting, or distributing electric energy, or (2) providing electric energy services that are necessary to support the reliable operation of the transmission system, or;

4. an Applicant or Market Participant seeking eligibility as an "appropriate person" providing an unlimited Corporate Guaranty in a form acceptable to PJM as described in section V below from a Guarantor that has demonstrated it is an "appropriate person," and has at least $1 million of total net worth or $5 million of total assets per Applicant and Market Participant for which the Guarantor has issued an unlimited Corporate Guaranty, or;

5. an Applicant or Market Participant providing a Letter of Credit of at least $5 million to PJM in a form acceptable to PJM as described in section V below, that the Applicant or Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJM, or;

6. an Applicant or Market Participant providing a surety bond of at least $5 million to PJM in a form acceptable to PJM as described in section V below, that the Applicant or Market Participant acknowledges is separate from, and cannot be applied to meet, its credit requirements to PJM.

If, at any time, a Market Participant cannot meet the eligibility requirements set forth above, it shall immediately notify PJM and immediately cease conducting transactions in any PJM Markets. PJM may terminate a Market Participant's transaction rights in any PJM Markets if, at any time, it becomes aware that the Market Participant does not meet the minimum eligibility requirements set forth above.

In the event that a Market Participant is no longer able to demonstrate it meets the minimum eligibility requirements set forth above, and possesses, obtains or has rights to possess or obtain, any open or forward positions in any PJM Markets, PJM may take any such action it deems necessary with respect to such open or forward positions, including, but not limited to, liquidation, transfer, assignment, sale or allowing position(s) to go to settlement; provided, however, that the Market Participant will, notwithstanding its ineligibility to participate in any PJM Markets, be entitled to any positive market value of those positions, net of any obligations due and owing to PJM.

C. Risk Management and Verification

All Market Participants must maintain current written risk management policies, procedures, or controls to address how market and credit risk is managed, and are required to submit to PJM (at the time they make their annual certification) a copy of their current governing risk control policies, procedures and controls applicable to their market activities. PJM will review such documentation to verify that it appears generally to conform to prudent risk management practices for entities participating in any PJM Markets.

All Market Participants subject to this provision shall make a one-time payment of $1,500.00 to PJM to cover administrative costs. Thereafter, if such Participant’s risk policies, procedures and controls applicable to its market activities change substantively, it shall submit such modified documentation, with applicable administrative charge determined by PJM, to PJM for review and verification at the time it makes its annual certification. All Market Participant’s continued eligibility to participate in any PJM Markets is conditioned on PJM notifying a Participant that its annual certification, including the submission of its risk policies, procedures and controls, has been accepted by PJM. PJM may retain outside expertise to perform the review and verification function described in this section, however, in all circumstances, PJM and any third-party it may retain will treat as confidential the documentation provided by a Participant under this section, consistent with the applicable provisions of the Operating Agreement.

Participants must demonstrate that they have implemented prudent risk management policies and procedures in order to be eligible to participate in any PJM Markets. Participants must demonstrate on at least an annual basis that they have implemented and maintained prudent risk management policies and procedures in order to continue to participate in any PJM Markets. Upon written request, the Participant will have fourteen (14) calendar days to provide to PJM current governing risk management policies, procedures, or controls applicable to Participant’s activities in any PJM Markets.

D. Capitalization

In advance of certification, Applicants shall meet the minimum capitalization requirements below. In addition to the annual certification requirements in Attachment Q, Appendix 1, a Market Participant shall satisfy the minimum capitalization requirements on an annual basis thereafter. A Participant must demonstrate that it meets the minimum financial requirements appropriate for the PJM Markets in which it transacts by satisfying either the minimum capitalization or the provision of Collateral requirements listed below:

1. Minimum Capitalization

Minimum capitalization may be met by demonstrating minimum levels of Tangible Net Worth or tangible assets. FTR Participants must demonstrate a Tangible Net Worth in excess of $1 million or tangible assets in excess of $10 million. Other Market Participants must demonstrate a Tangible Net Worth in excess of $500,000 or tangible assets in excess of $5 million.

(a) Consideration of tangible assets and Tangible Net Worth shall exclude assets which PJM reasonably believes to be restricted, highly risky, or potentially unavailable to settle a claim in the event of default. Examples include, but are not limited to, restricted assets, derivative assets, goodwill, and other intangible assets.

(b) Demonstration of "tangible" assets and Tangible Net Worth may be satisfied through presentation of an acceptable Corporate Guaranty, provided that both:

(i) the Guarantor is a Credit Affiliate company that satisfies the Tangible Net Worth or tangible assets requirements herein, and;

(ii) the Corporate Guaranty is either unlimited or at least $500,000.

If the Corporate Guaranty presented by the Participant to satisfy these capitalization requirements is limited in value, then the Participant's resulting Unsecured Credit Allowance shall be the lesser of:

(1) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this Attachment Q, or,

(2) the face value of the Corporate Guaranty, reduced by $500,000 and further reduced by 10%. (For example, a $10.5 million Corporate Guaranty would be reduced first by $500,000 to $10 million and then further reduced 10% more to $9 million. The resulting $9 million would be the Participant's Unsecured Credit Allowance available through the Corporate Guaranty).

In the event that a Participant provides Collateral in addition to a limited Corporate Guaranty to increase its available credit, the value of such Collateral shall be reduced by 10%. This reduced value shall be considered the amount available to satisfy requirements of this Attachment Q.

(c) Demonstrations of minimum capitalization (minimum Tangible Net Worth or tangible assets) must be presented in the form of audited financial statements for the Participant's most recent fiscal year during the initial risk evaluation process and ongoing risk evaluation process.

2. Provision of Collateral

If a Participant does not demonstrate compliance with its applicable minimum capitalization requirements above, it may still qualify to participate in any PJM Markets by posting Collateral, additional Collateral, and/or Restricted Collateral, subject to the terms and conditions set forth herein.

Any Collateral provided by a Participant unable to satisfy the minimum capitalization requirements above will also be restricted in the following manner:

(a) Collateral provided by Market Participants that engage in FTR transactions shall be reduced by an amount of the current risk plus any future risk to any PJM Markets and PJM membership in general, and may coincide with limitations on market participation. The amount of this Restricted Collateral shall not be available to cover any credit requirements from market activity. The remaining value shall be considered the amount available to satisfy requirements of this Attachment Q.

(b) Collateral provided by other Participants that engage in Virtual Transactions or Export Transactions shall be reduced by $200,000 and then further reduced by 10%. The amount of this Restricted Collateral shall not be available to cover any credit requirements from market activity. The remaining value shall be considered the amount available to satisfy requirements of this Attachment Q.

(c) Collateral provided by other Participants that do not engage in Virtual Transactions or Export Transactions shall be reduced by 10%. The amount of this Restricted Collateral shall not be available to cover any credit requirements from market activity. The remaining value shall be considered the amount available to satisfy requirements of this Attachment Q.

In the event a Participant that satisfies the minimum capital requirement through provision of Collateral also provides a Corporate Guaranty to increase its available credit, then the Participant's resulting Unsecured Credit Allowance conveyed through such Corporate Guaranty shall be the lesser of:

(a) the applicable Unsecured Credit Allowance available to the Participant by the Corporate Guaranty pursuant to the creditworthiness provisions of this Attachment Q; or

(b) the face value of the Corporate Guaranty, reduced commensurate with the amount of the current risk plus any anticipated future risk to any PJM Markets and PJM membership in general, and may coincide with limitations on market participation.

IV. ONGOING COVENANTS

A. Ongoing Obligation to Provide Information to PJM

So long as a Participant is eligible to participate, or participates or holds positions, in any PJM Markets, it shall deliver to PJM, in form and detail satisfactory to PJM:

(1) All financial statements and other financial disclosures as required by section II.E.2 by the deadline set forth therein;

(2) Notice, within five (5) Business Days, of any Principal becoming aware that the Participant does not meet the Minimum Participation Requirements set forth in section III;

(3) Notice when any Principal becomes aware of any matter that has resulted or would reasonably be expected to result in a Material Adverse Change in the financial condition of the Participant or its Guarantor, if any, a description of such Material Adverse Change in detail reasonable to allow PJM to determine its potential effect on, or any change in, the Participant's risk profile as a participant in any PJM Markets, by the deadline set forth in section II.E.3 above;

(4) Notice, within the deadline set forth therein, of any Principal becoming aware of a litigation or contingency event described in section II.E.4, or of a Material Adverse Change in any such litigation or contingency event previously disclosed to PJM, information in detail reasonable to allow PJM to determine its potential effect on, or any change in, the Market Participant's risk profile as a participant in any PJM Markets by the deadline set forth therein;

(5) Notice, within two (2) Business Days after any Principal becomes aware of a Credit Breach, Financial Default, or Credit Support Default, that includes a description of such default or event and the Participant's proposals for addressing the default or event;

(6) As soon as available but not later than April 30th of any calendar year, the annual Certification described in section III.A in a form set forth in Attachment Q, Appendix 1;

(7) Concurrently with submission of the annual certification, demonstration that the Participant meets the minimum capitalization requirements set forth in section III.D;

(8) Concurrently with submission of the annual certification and within the applicable deadline of any substantive change, or within the applicable deadline of a request from PJM, a copy of the Participant's written risk management policies, procedures or controls addressing how the Participant manages market and credit risk in the PJM Markets in which it participates, as well as a high level summary by the chief risk officer or other Principal regarding any material violations, breaches, or compliance or disciplinary actions related to the risk management policies, by the Participant under the policies, procedures or controls within the prior 12 months, as set forth in section VI.B below;

(9) Within five (5) Business Days of request by PJM, evidence demonstrating the Participant meets the definition of "appropriate person" or "eligible contract participant," as those terms are defined in the Commodity Exchange Act and the CFTC regulations promulgated thereunder, or of any other certification in the annual Certification; or

(10) Within a reasonable time after PJM requests, any other information or documentation reasonably and/or legally required by PJM to confirm Participant's compliance with the Tariff and its eligibility to participate in any PJM Markets.

Participants acknowledge and understand that the deliveries constitute representations upon which PJM will rely in allowing the Participant to continue to participate in its markets, with the Internal Credit Score and Unsecured Credit Allowance, if any, previously determined by PJM.

B. Risk Management Review

PJM shall also conduct a periodic compliance verification process to review and verify, as applicable, Participants' risk management policies, practices, and procedures pertaining to the Participant's activities in any PJM Markets. PJM shall review such documentation to verify that it appears generally to conform to prudent risk management practices for entities trading in any PJM Markets. Participant shall also provide a high level summary by the chief risk officer or other Principal regarding any material violations, breaches, or compliance or disciplinary actions in connection with such risk management policies, practices and procedures within the prior twelve (12) months.

If a third-party industry association publishes or modifies principles or best practices relating to risk management in North American markets for electricity, natural gas or electricity-related commodity products, PJM may, following stakeholder discussion and with no less than six (6) months prior notice to stakeholders, consider such principles or best practices in evaluating the Participant's risk controls.

PJM will prioritize the verification of risk management policies based on a number of criteria, including but not limited to how long the entity has been in business, the Participant's and its Principals' history of participation in any PJM Markets, and any other information obtained in determining the risk profile of the Participant.

Each Participant's continued eligibility to participate in any PJM Markets is conditioned upon PJM notifying the Participant of successful completion of PJM's verification of the Participant's risk management policies, practices and procedures, as discussed herein. However, if PJM notifies the Participant in writing that it could not successfully complete the verification process, PJM shall allow such Participant fourteen (14) calendar days to provide sufficient evidence for verification prior to declaring the Participant as ineligible to continue to participate in any PJM Markets, which declaration shall be in writing with an explanation of why PJM could not complete the verification. If the Participant does not provide sufficient evidence for verification to PJM within the required cure period, such Participant will be considered in default under this Tariff. PJM may retain outside expertise to perform the review and verification function described in this paragraph. PJM and any third party it may retain will treat as confidential the documentation provided by a Participant under this paragraph, consistent with the applicable provisions of the Agreements. If PJM retains such outside expertise, a Participant may direct in writing that PJM perform the risk management review and verification for such Participant instead of utilizing a third party, provided however, that employees and contract employees of PJM shall not be considered to be such outside expertise or third parties.

Participants are solely responsible for the positions they take and the obligations they assume in any PJM Markets. PJM hereby disclaims any and all responsibility to any Participant or PJM

Member associated with Participant's submitting or failure to submit its annual certification or PJM's review and verification of a Participant's risk policies, procedures and controls. Such review and verification is limited to demonstrating basic compliance by a Participant showing the existence of written policies, procedures and controls to limit its risk in any PJM Markets and does not constitute an endorsement of the efficacy of such policies, procedures or controls.

V. FORMS OF CREDIT SUPPORT

In order to satisfy their PJM credit requirements Participants may provide credit support in a PJM-approved form and amount pursuant to the guidelines herein, provided that, notwithstanding anything to the contrary in this section, a Market Participant in PJM's FTR markets shall meet its credit support requirements related to those FTR markets with either cash or Letters of Credit.

Unless otherwise restricted by PJM, credit support provided may be used by PJM to secure the payment of Participant's financial obligations under the Agreements.

Collateral which may no longer be required to be maintained under provisions of the Agreements, shall be returned at the request of a Participant, no later than two (2) Business Days following determination by PJM within a commercially reasonable period of time that such Collateral is not required.

Except when an Event of Default has occurred, a Participant may substitute an approved PJM form of Collateral for another PJM approved form of Collateral of equal value.

A. Cash Deposit

A Participant's delivery of a cash deposit to PJM as Collateral shall constitute the grant of a first-priority security interest in the cash in favor of PJM and PJM shall be authorized by such delivery to hold the cash as security and to apply it to the Participant's financial obligations under the Tariff or other Agreements. Cash provided by a Participant as Collateral will be held in a depository account by PJM. Interest on a cash deposit shall accrue to the benefit of the Participant, provided that PJM may require Participants to provide appropriate tax and other information in order to accrue such interest credits. A Participant who delivers cash to PJM hereunder agrees that the Tariff and any other agreements incorporating the terms of the Tariff shall for all purposes constitute a security agreement.

Cash Collateral may not be pledged or in any way encumbered or restricted from full and timely use by PJM in accordance with terms of the Agreements.

PJM has the right to liquidate all or a portion of the Collateral account balance at its discretion to satisfy a Participant's Total Net Obligation to PJM in the Event of Default under this Attachment Q or one or more of the Agreements.

B. Letter of Credit

An unconditional, irrevocable standby Letter of Credit can be utilized to meet the Collateral requirement. As stated below, the form, substance, and provider of the Letter of Credit must all be acceptable to PJM.

(1) The Letter of Credit will only be accepted from U.S.-based financial institutions or U.S. branches of foreign financial institutions ("financial institutions") that have a minimum corporate debt rating of "A" by Standard & Poor's or Fitch Ratings, or "A2" from Moody's Investors Service, or an equivalent short term rating from one of these agencies. PJM will consider the lowest applicable rating to be the rating of the financial institution. If the rating of a financial institution providing a Letter of Credit is lowered below A/A2 by any Rating Agency, then PJM may require the Participant to provide a Letter of Credit from another financial institution that is rated A/A2 or better, or to provide a cash deposit. If a Letter of Credit is provided from a U.S. branch of a foreign institution, the U.S. branch must itself comply with the terms of this Attachment Q, including having its own acceptable credit rating.

(2) The Letter of Credit shall state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety (90) calendar days prior written notice from the issuing financial institution. If PJM or PJM receives notice from the issuing financial institution that the current Letter of Credit is being cancelled or expiring, the Participant will be required to provide evidence, acceptable to PJM, that such Letter of Credit will be replaced with appropriate Collateral, effective as of the cancellation date of the Letter of Credit, no later than thirty (30) calendar days before the cancellation date of the Letter of Credit, and no later than ninety (90) calendar days after the notice of cancellation. Failure to do so will constitute a default under this Attachment Q and one or more of the Agreements.

(3) PJM will post on its web site an acceptable standard form of a Letter of Credit that should be utilized by a Participant choosing to submit a Letter of Credit to establish credit at PJM. If the Letter of Credit varies in any way from the standard format, it must first be reviewed and approved by PJM. All costs associated with obtaining and maintaining a Letter of Credit and meeting the Attachment Q provisions are the responsibility of the Participant.

(4) PJM may accept a Letter of Credit from a financial institution that does not meet the credit standards of this Attachment Q provided that the Letter of Credit has third-party support, in a form acceptable to PJM, from a financial institution that does meet the credit standards of this Attachment Q.

C. Corporate Guaranty

An irrevocable and unconditional Corporate Guaranty may be utilized to establish an Unsecured Credit Allowance for a Participant. Such credit will be considered a transfer of Unsecured Credit from the Guarantor to the Participant, and will not be considered a form of Collateral.

PJM will post on its web site an acceptable form that should be utilized by a Participant choosing to establish its credit with a Corporate Guaranty. If the Corporate Guaranty varies in any way

from the PJM format, it must first be reviewed and approved by PJM before it may be applied to satisfy the Participant's credit requirements.
The Corporate Guaranty must be signed by an officer of the Guarantor, and must demonstrate that it is duly authorized in a manner acceptable to PJM. Such demonstration may include either a corporate seal on the Corporate Guaranty itself, or an accompanying executed and sealed secretary's certificate from the Guarantor's corporate secretary noting that the Guarantor was duly authorized to provide such Corporate Guaranty and that the person signing the Corporate Guaranty is duly authorized, or other manner acceptable to PJM.

PJM will evaluate the creditworthiness of a Guarantor and will establish any Unsecured Credit granted through a Corporate Guaranty using the methodology and requirements established for Participants requesting an Unsecured Credit Allowance as described herein. Foreign Guaranties and Canadian Guaranties shall be subject to additional requirements as established herein.
If PJM determines at any time that a Material Adverse Change in the financial condition of the Guarantor has occurred, or if the Corporate Guaranty comes within thirty (30) calendar days of expiring without renewal, PJM may reduce or eliminate any Unsecured Credit afforded to the Participant through the guaranty. Such reduction or elimination may require the Participant to provide Collateral within the applicable cure period. If the Participant fails to provide the required Collateral, the Participant shall be in default under this Attachment Q.

All costs associated with obtaining and maintaining a Corporate Guaranty and meeting the Attachment Q provisions are the responsibility of the Participant.

1. Foreign Guaranties

A Foreign Guaranty is a Corporate Guaranty that is provided by a Credit Affiliate entity that is domiciled in a country other than the United States or Canada. The entity providing a Foreign Guaranty on behalf of a Participant is a Foreign Guarantor. A Participant may provide a Foreign Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJM provided that all of the following conditions are met:

PJM reserves the right to deny, reject, or terminate acceptance of any Foreign Guaranty at any time, including for material adverse circumstances or occurrences.

(a) A Foreign Guaranty:
- (i) Must contain provisions equivalent to those contained in PJM's standard form of Foreign Guaranty with any modifications subject to review and approval by PJM counsel.
- (ii) Must be denominated in US currency.
- (iii) Must be written and executed solely in English, including any duplicate originals.
- (iv) Will not be accepted towards a Participant's Unsecured Credit Allowance for more than the following limits, depending on the Foreign Guarantor's credit rating:

Rating of Foreign Guarantor	Maximum Accepted Guaranty if Country Rating is AAA	Maximum Accepted Guaranty if Country Rating is AA+
A- and above	USD50,000,000	USD30,000,000
BBB+	USD30,000,000	USD20,000,000
BBB	USD10,000,000	USD10,000,000
BBB- or below	USD 0	USD 0

(v) May not exceed 50% of the Participant's total credit, if the Foreign Grantor is rated less than BBB+.

(b) A Foreign Guarantor:

(i) Must satisfy all provisions of this Attachment Q applicable to domestic Guarantors.

(ii) Must be a Credit Affiliate of the Participant.

(iii) Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.

(iv) Must be rated by at least one Rating Agency acceptable to PJM; the credit strength of a Foreign Guarantor may not be determined based on an evaluation of its audited financial statements without an actual credit rating as well.

(v) Must have a senior unsecured (or equivalent, in PJM's sole discretion) rating of BBB (one notch above BBB-) or greater by any and all agencies that provide rating coverage of the entity.

(vi) Must provide audited financial statements, in US GAAP format or any other format acceptable to PJM, with clear representation of net worth, intangible assets, and any other information PJM may require in order to determine the entity's Unsecured Credit Allowance.

(vii) Must provide a Secretary's Certificate from the Participant's corporate secretary certifying the adoption of Corporate Resolutions:

1. Authorizing and approving the Guaranty; and
2. Authorizing the Officers to execute and deliver the Guaranty on behalf of the Guarantor.

(viii) Must be domiciled in a country with a minimum long-term sovereign (or equivalent) rating of AA+/Aa1, with the following conditions:

1. Sovereign ratings must be available from at least two rating agencies acceptable to PJM (e.g. S&P, Moody's, Fitch, DBRS).
2. Each agency's sovereign rating for the domicile will be considered to be the lowest of: country ceiling, senior unsecured government debt, long-term foreign currency sovereign rating, long-term local currency sovereign rating, or other equivalent measures, at PJM's sole discretion.
3. Whether ratings are available from two or three agencies, the lowest of the two or three will be used.

(ix) Must be domiciled in a country that recognizes and enforces judgments of US courts.

(x) Must demonstrate financial commitment to activity in the United States as evidenced by one of the following:

1. American Depository Receipts (ADR) are traded on the New York Stock Exchange, American Stock Exchange, or NASDAQ.
2. Equity ownership worth over USD 100,000,000 in the wholly-owned or majority owned subsidiaries in the United States.

(xi) Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Attachment Q.

(xii) Must pay for all expenses incurred by PJM related to reviewing and accepting a foreign guaranty beyond nominal in-house credit and legal review.

(xiii) Must, at its own cost, provide PJM with independent legal opinion from an attorney/solicitor of PJM's choosing and licensed to practice law in the United States and/or Guarantor's domicile, in form and substance acceptable to PJM in its sole discretion, confirming the enforceability of the Foreign Guaranty, the Guarantor's legal authorization to grant the Guaranty, the conformance of the Guaranty, Guarantor, and Guarantor's domicile to all of these requirements, and such other matters as PJM may require in its sole discretion.

2. Canadian Guaranties

The entity providing a Canadian Guaranty on behalf of a Participant is a Canadian Guarantor. A Participant may provide a Canadian Guaranty in satisfaction of part of its credit obligations or voluntary credit provision at PJM provided that all of the following conditions are met.

PJM reserves the right to deny, reject, or terminate acceptance of any Canadian Guaranty at any time for reasonable cause, including material adverse circumstances or occurrences.

(a) A Canadian Guaranty:

(i) Must contain provisions equivalent to those contained in PJM's standard form of Foreign Guaranty with any modifications subject to review and approval by PJM counsel.

(ii) Must be denominated in US currency.

(iii) Must be written and executed solely in English, including any duplicate originals.

(b) A Canadian Guarantor:

(i) Must be a Credit Affiliate of the Participant.

(ii) Must satisfy all provisions of this Attachment Q applicable to domestic Guarantors.

(iii) Must maintain an agent for acceptance of service of process in the United States; such agent shall be situated in the Commonwealth of Pennsylvania, absent legal constraint.

(iv) Must be rated by at least one Rating Agency acceptable to PJM; the credit strength of a Canadian Guarantor may not be determined based on an evaluation of its audited financial statements without an actual credit rating as well.

(v) Must provide audited financial statements, in US GAAP format or any other format acceptable to PJM with clear representation of net worth, intangible assets, and any other information PJM may require in order to determine the entity's Unsecured Credit Allowance.

(vi) Must satisfy all other applicable provisions of the PJM Tariff and/or Operating Agreement, including this Attachment Q.

D. Surety Bond

An unconditional, irrevocable surety bond can be utilized to meet the Collateral requirement for Participants. As stated below, the form, substance, and provider of the surety bond must all be acceptable to PJM.

(i) An acceptable surety bond must be payable immediately upon demand without prior demonstration of the validity of the demand. The surety bond will only be accepted from a U.S. Treasury-listed approved surety that has either (i) a minimum corporate debt rating of “A” by Standard & Poor’s or Fitch Ratings, or “A2” from Moody’s Investors Service, or an equivalent short term rating from one of these agencies, or (ii) a minimum insurer rating of “A” by A.M. Best. PJMSettlement will consider the lowest applicable rating to be the rating of the surety. If the rating of a surety providing a surety bond is lowered below A/A2 by any rating agency, then PJMSettlement may require the Participant to provide a surety bond from another surety that is rated A/A2 or better, or to provide another form of Collateral.

(ii) The surety bond shall have an initial period of at least one year, and shall state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety (90) days prior written notice from the issuing surety. If PJM receives notice from the issuing surety that the current surety bond is being cancelled, the Participant will be required to provide evidence, acceptable to PJM, that such surety bond will be replaced with appropriate Collateral, effective as of the cancellation date of the surety bond, no later than thirty (30) days before the cancellation date of the surety bond, and no later than ninety (90) days after the notice of cancellation. Failure to do so will constitute a default under this Attachment Q and one of more of the Agreements enabling PJM to immediately demand payment of the full value of the surety bond.

(iii) PJM will post on its web site an acceptable standard form of a surety bond that should be utilized by a Participant choosing to submit a surety bond to establish credit at PJM. The acceptable standard form of surety bond will include non-negotiable provisions, including but not be limited to, a payment on demand feature, requirement that the bond be construed pursuant to Pennsylvania law, making the surety’s obligation to pay out on the bond absolute and unconditional irrespective of the principal’s (Market Participant’s) bankruptcy, terms of any other agreements, investigation of the Market Participant by any entity or governmental authority, or PJM first attempting to collect payment from the Market Participant, and will require, among other things, that (a) the surety waive ***all*** rights that would be available to a principal or surety under the law, including but not limited to any right to investigate or verify any matter related to a demand for payment, rights to set-off amounts due by PJM to the Market Participant, and all counterclaims, (b) the surety expressly waive ***all*** of its and the principal’s defenses, including illegality, fraud in the inducement, reliance on statements or representations of PJM and every other typically available defense; (c) the language of the bond that is determinative of the surety's obligation, and not the underlying agreement or arrangement between the principal and the oblige; (d) the bond shall not be conditioned on PJM first resorting to any other means of security or collateral, or pursuing any other remedies it may have; and (e) the surety acknowledge the continuing nature of its obligations in the event of termination or nonrenewal of the surety bond to make clear the surety remains liable for any obligations that arose before the effective date of its notice of cancellation of the surety bond. If the surety bond varies in any way from the standard format, it must first be reviewed and approved by PJM. PJM shall not accept any surety bond that varies in any material way from the standard format.

(iv) All costs associated with obtaining and maintaining a surety bond and meeting the Attachment Q provisions are the responsibility of the Participant.

(v) PJM shall not accept surety bonds with an aggregate value greater than $10 million dollars ($10,000,000) issued by any individual surety on behalf of any individual Participant.

(vi) PJM shall not accept surety bonds with an aggregate value greater than $50 million dollars ($50,000,000) issued by any individual surety.

E. PJM Administrative Charges

Collateral or credit support held by PJM shall also secure obligations to PJM for PJM administrative charges, and may be liquidated to satisfy all such obligations in an Event of Default.

F. Collateral and Credit Support Held by PJM

Collateral or credit support submitted by Participants and held by PJM shall be held by PJM for the benefit of PJM.

VI. SUPPLEMENTAL CREDIT REQUIREMENTS FOR SCREENED TRANSACTIONS

A. Virtual and Export Transaction Screening

1. Credit for Virtual and Export Transactions

Export Transactions and Virtual Transactions both utilize Credit Available for Virtual Transactions to support their credit requirements.

PJM does not require a Market Participant to establish separate or additional credit for submitting Virtual or Export Transactions; however, once transactions are submitted and accepted by PJM, PJM may require credit supporting those transactions to be held until the transactions are completed and their financial impact incorporated into the Market Participant's Obligations. If a Market Participant chooses to establish additional Collateral and/or Unsecured Credit Allowance in order to increase its Credit Available for Virtual Transactions, the Market Participant's Working Credit Limit for Virtual Transactions shall be increased in accordance with the definition thereof. The Collateral and/or Unsecured Credit Allowance available to increase a Market Participant's Credit Available for Virtual Transactions shall be the amount of Collateral and/or Unsecured Credit Allowance available after subtracting any credit required for Minimum Participation Requirements, FTR, RPM or other credit requirement determinants defined in this Attachment Q, as applicable.

If a Market Participant chooses to provide additional Collateral in order to increase its Credit Available for Virtual Transactions PJM may establish a reasonable timeframe, not to exceed three months, for which such Collateral must be maintained. PJM will not impose such restriction on a deposit unless a Market Participant is notified prior to making the deposit. Such restriction, if applied, shall be applied to all future deposits by all Market Participants engaging in Virtual Transactions.

A Market Participant may increase its Credit Available for Virtual Transactions by providing additional Collateral to PJM. PJM will make a good faith effort to make new Collateral available as Credit Available for Virtual Transactions as soon as practicable after confirmation of receipt. In any event, however, Collateral received and confirmed by noon on a Business Day will be applied (as provided under this Attachment Q) to Credit Available for Virtual Transactions no later than 10:00 am on the following Business Day. Receipt and acceptance of wired funds for cash deposit shall mean actual receipt by PJM's bank, deposit into PJM's customer deposit account, confirmation by PJM that such wire has been received and deposited, and entry into PJM's credit system. Receipt and acceptance of letters of credit or surety bonds shall mean receipt of the original Letter of Credit or surety bond, or amendment thereto, confirmation from PJM's credit and legal staffs that such Letter of Credit or surety bond, or amendment thereto conforms to PJM's requirements, which confirmation shall be made in a reasonable and practicable timeframe, and entry into PJM's credit system. To facilitate this process, bidders submitting additional Collateral for the purpose of increasing their Credit Available for Virtual Transactions are advised to submit such Collateral well in advance of the desired time, and to specifically notify PJM of such submission.

A Market Participant wishing to submit Virtual or Export Transactions must allocate within PJM's credit system the appropriate amount of Credit Available for Virtual Transactions to the virtual and export allocation sections within each customer account in which it wishes to submit such transactions.

2. Virtual Transaction Screening

All Virtual Transactions submitted to PJM shall be subject to a credit screen prior to acceptance in the Day-ahead Energy Market. The credit screen is applied separately for each of a Market Participant's customer accounts. The credit screen process will automatically reject Virtual Transactions submitted by the Market Participant in a customer account if the Market

Participant's Credit Available for Virtual Transactions, allocated on a customer account basis, is exceeded by the Virtual Credit Exposure that is calculated based on the Market Participant's Virtual Transactions submitted, as described below.

A Market Participant's Virtual Credit Exposure will be calculated separately for each customer account on a daily basis for all Virtual Transactions submitted by the Market Participant for the next Operating Day using the following equation:

Virtual Credit Exposure = INC and DEC Exposure + Up-to Congestion Exposure
Where:

(a) INC and DEC Exposure for each customer account is calculated as:

(i) ((the total MWh bid or offered, whichever is greater, hourly at each node) x the Nodal Reference Price x 1 day) summed over all nodes and all hours; plus (ii) ((the difference between the total bid MWh cleared and total offered MWh cleared hourly at each node) x Nodal Reference Price) summed over all nodes and all hours for the previous cleared Day-ahead Energy Market.

(b) Up-to Congestion Exposure for each customer account is calculated as:

(i) Total MWh bid hourly for each Up-to Congestion Transaction x (price bid – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours; plus (ii) Total MWh cleared hourly for each Up-to Congestion Transaction x (cleared price – Up-to Congestion Reference Price) summed over all Up-to Congestion Transactions and all hours for the previous cleared Day-ahead Energy Market, provided that hours for which the calculation for an Up-to Congestion Transaction is negative, it shall be deemed to have a zero contribution to the sum.

3. Export Transaction Screening

Export Transactions in the Real-time Energy Market shall be subject to Export Transaction Screening. Export Transaction Screening may be performed either for the duration of the entire Export Transaction, or separately for each time interval comprising an Export Transaction. PJM will deny or curtail all or a portion (based on the relevant time interval) of an Export Transaction if that Export Transaction, or portion thereof, would otherwise cause the Market Participant's Export Credit Exposure to exceed its Credit Available for Export Transactions. Export Transaction Screening shall be applied separately for each Operating Day and shall also be applied to each Export Transaction one or more times prior to the market clearing process for each relevant time interval. Export Transaction Screening shall not apply to transactions established directly by and between PJM and a neighboring Balancing Authority for the purpose of maintaining reliability.

A Market Participant's credit exposure for an individual Export Transaction shall be the MWh volume of the Export Transaction for each relevant time interval multiplied by each relevant

Export Transaction Price Factor and summed over all relevant time intervals of the Export Transaction.

B. RPM Auction and Price Responsive Demand Credit Requirements

Settlement during any Delivery Year of cleared positions resulting or expected to result from any RPM Auction shall be included as appropriate in Peak Market Activity, and the provisions of this Attachment Q shall apply to any such activity and obligations arising therefrom. In addition, the provisions of this section shall apply to any entity seeking to participate in any RPM Auction, to address credit risks unique to such auctions. The provisions of this section also shall apply under certain circumstances to PRD Providers that seek to commit Price Responsive Demand pursuant to the provisions of the Reliability Assurance Agreement.

Credit requirements described herein for RPM Auctions and RPM bilateral transactions are applied separately for each customer account of a Market Participant. Market Participants wishing to participate in an RPM Auction or enter into RPM bilateral transactions must designate the appropriate amount of credit to each account in which their offers are submitted.

1. Applicability

A Market Participant seeking to submit a Sell Offer in any RPM Auction based on any Capacity Resource for which there is a materially increased risk of nonperformance must satisfy the credit requirement specified herein before submitting such Sell Offer. A PRD Provider seeking to commit Price Responsive Demand for which there is a materially increased risk of non-performance must satisfy the credit requirement specified herein before it may commit the Price Responsive Demand. Credit must be maintained until such risk of non-performance is substantially eliminated, but may be reduced commensurate with the reduction in such risk, as set forth in section VI.B.3 below.

For purposes of this provision, a resource for which there is a materially increased risk of nonperformance shall mean: (i) a Planned Generation Capacity Resource; (ii) a Planned Demand Resource or an Energy Efficiency Resource; (iii) a Qualifying Transmission Upgrade; (iv) an existing or Planned Generation Capacity Resource located outside the PJM Region that at the time it is submitted in a Sell Offer has not secured firm transmission service to the border of the PJM Region sufficient to satisfy the deliverability requirements of the Reliability Assurance Agreement; or (v) Price Responsive Demand to the extent the responsible PRD Provider has not registered PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Reliability Assurance Agreement, Schedule 6.1.

2. Reliability Pricing Model Auction and Price Responsive Demand Credit Requirement

Except as provided for Credit-Limited Offers below, for any resource specified in section VI.B.1 above, other than Price Responsive Demand, the credit requirement shall be the RPM Auction Credit Rate, as provided in section VI.B.4 below, times the megawatts to be offered for sale from such resource in an RPM Auction. For Qualified Transmission Upgrades, the credit requirements shall be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit. The RPM Auction Credit Requirement for each Market Participant shall be determined on a customer account basis, separately for each customer account of a Market Participant, and shall be the sum of the credit requirements for all such resources to be offered by such Market Participant in the auction or, as applicable, cleared by such Market Participant in the relevant auctions. For Price Responsive Demand, the credit requirement shall be based on the Nominal PRD Value (stated in Unforced Capacity terms) times the Price Responsive Demand Credit Rate as set forth in section VI.B.5 below. Except for Credit-Limited Offers, the RPM Auction Credit requirement for a Market Participant will be reduced for any Delivery Year to the extent less than all of such Market Participant's offers clear in the Base Residual Auction or any Incremental Auction for such Delivery Year. Such reduction shall be proportional to the quantity, in megawatts, that failed to clear in such Delivery Year.

A Sell Offer based on a Planned Generation Capacity Resource, Planned Demand Resource, or Energy Efficiency Resource may be submitted as a Credit-Limited Offer. A Market Participant electing this option shall specify a maximum amount of Unforced Capacity, in megawatts, and a maximum credit requirement, in dollars, applicable to the Sell Offer. A Credit-Limited Offer shall clear the RPM Auction in which it is submitted (to the extent it otherwise would clear based on the other offer parameters and the system's need for the offered capacity) only to the extent of the lesser of: (i) the quantity of Unforced Capacity that is the quotient of the division of the specified maximum credit requirement by the Auction Credit Rate resulting from section VI.B.4.b. below; and (ii) the maximum amount of Unforced Capacity specified in the Sell Offer. For a Market Participant electing this alternative, the RPM Auction Credit requirement applicable prior to the posting of results of the auction shall be the maximum credit requirement specified in its Credit-Limited Offer, and the RPM Auction Credit requirement subsequent to posting of the results will be the Auction Credit Rate, as provided in section VI.B.4.b, c. or d. of this Attachment Q, as applicable, times the amount of Unforced Capacity from such Sell Offer that cleared in the auction. The availability and operational details of Credit-Limited Offers shall be as described in the PJM Manuals.

As set forth in section VI.B.4 below, a Market Participant's Auction Credit requirement shall be determined separately for each Delivery Year.

3. Reduction in Credit Requirement

As specified below, the RPM Auction Credit Rate may be reduced under certain circumstances after the auction has closed.

The Price Responsive Demand credit requirement shall be reduced as and to the extent the PRD Provider registers PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment, in accordance with Reliability Assurance Agreement, Schedule 6.1.

In addition, the RPM Auction Credit requirement for a Market Participant for any given Delivery Year shall be reduced periodically, after the Market Participant has provided PJM a written request for each reduction, accompanied by documentation sufficient for PJM to verify attainment of required milestones or satisfaction of other requirements, and PJM has verified that the Market Participant has successfully met progress milestones for its Capacity Resource that reduce the risk of non-performance, as follows:

(a) For Planned Demand Resources and Energy Efficiency Resources, the RPM Auction Credit requirement will be reduced in direct proportion to the megawatts of such Demand Resource that the Resource Provider qualifies as a Capacity Resource, in accordance with the procedures established under the Reliability Assurance Agreement.

(b) For Existing Generation Capacity Resources located outside the PJM Region that have not secured sufficient firm transmission to the border of the PJM Region prior to the auction in which such resource is first offered, the RPM Auction Credit requirement shall be reduced in direct proportion to the megawatts of firm transmission service secured by the Market Participant that qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

(c) For Planned Generation Capacity Resources located in the PJM Region, the RPM Auction Credit requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals.

Milestones	Increment of reduction from initial RPM Auction Credit requirement
Effective Date of Interconnection Service Agreement, Generation Interconnection Agreement or Wholesale Market Participation Agreement	50%
Financial Close	15%
Full Notice to Proceed and Commencement of Construction (e.g., footers poured)	5%
Main Power Generating Equipment Delivered	5%
Commencement of Interconnection Service	25%

For externally financed projects, the Market Participant must submit with its request for reduction a sworn, notarized certification of a duly authorized independent engineer for the Financial Close, Full Notice to Proceed and Commencement of Construction, and Main Power Generating Equipment Delivered milestones.

For internally financed projects, the Market Participant must submit with its request for reduction a sworn, notarized certification of a duly authorized officer of the Market Participant for the Financial Close milestone and either a duly authorized independent engineer or Professional Engineer for the Full Notice to Proceed and Commencement of Construction and the Main Power Generating Equipment Delivered milestones.

The required certifications must be in a form acceptable to PJM, certifying that the engineer or officer, as applicable, has personal knowledge, or has engaged in a diligent inquiry to determine, that the milestone has been achieved and that, based on its review of the relevant project information, the engineer or officer, as applicable, is not aware of any information that could reasonably cause it to believe that the Capacity Resource will not be in-service by the beginning of the applicable Delivery Year. The Market Participant shall, if requested by PJM, supply to PJM on a confidential basis all records and documents relating to the engineer's and/or officer's certifications.

(d) For Planned External Generation Capacity Resources, the RPM Auction Credit requirement shall be reduced as the Capacity Resource attains the milestones stated in the following table and as further described in the PJM Manuals; provided, however, that the total percentage reduction in the RPM Auction Credit requirement shall be no greater than the quotient of (i) the MWs of firm transmission service that the Market Participant has secured for the complete transmission path divided by (ii) the MWs of firm transmission service required to qualify such resource under the deliverability requirements of the Reliability Assurance Agreement.

Credit Reduction Milestones for Planned External Generation Capacity Resources

Milestones	Increment of reduction from initial RPM Auction Credit requirement
Effective Date of the equivalent of an Interconnection Service Agreement, Generation Interconnection Agreement or Wholesale Market Participation Agreement	50%
Financial Close	15%
Full Notice to Proceed and Commencement of Construction (e.g., footers poured)	5%
Main Power Generating Equipment Delivered	5%
Commencement of Interconnection Service	25%

To obtain a reduction in its RPM Auction Credit requirement, the Market Participant must demonstrate satisfaction of the applicable milestone in the same manner as set forth for Planned Generation Capacity Resources in subsection (c) above.

(e) For Qualifying Transmission Upgrades, the RPM Auction Credit requirement shall be reduced to 50% of the amount calculated under section VI.B.2 above beginning as of the effective date of the latest associated Interconnection Service Agreement or Generation Interconnection Agreement (or, when a project will have no such agreement, an Upgrade Construction Service Agreement), and shall be reduced to zero on the date the Qualifying Transmission Upgrade is placed in service.

4. RPM Auction Credit Rate

As set forth in the PJM Manuals, a separate Auction Credit Rate shall be calculated for each Delivery Year prior to each RPM Auction for such Delivery Year, as follows:

(a) Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Auction Credit Rate shall be:

(i) For Capacity Performance Resources, the greater of ((A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in MW-day or (B) $20 per MW-day) times the number of calendar days in such Delivery Year.

(ii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season.

(b) Subsequent to the posting of the results from a Base Residual Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational

Deliverability Area within which the resource is located) or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of calendar days in such Delivery Year).

(ii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season.

(c) For any resource not previously committed for a Delivery Year that seeks to participate in an Incremental Auction, the Auction Credit Rate shall be:

(i) For Capacity Performance Resources, the (greater of (A) 0.5 times Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA or (B) $20/MW-day) times the number of calendar days in such Delivery Year.

(d) Subsequent to the posting of the results of an Incremental Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:

(i) For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of calendar days in such Delivery Year); and

(ii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season.

(e) For the purposes of this section VI.B.4 and section VI.B.5 below, “Relevant LDA” means the Locational Deliverability Area in which the Capacity Performance Resource is located if a separate Variable Resource Requirement Curve has been established for that Locational Deliverability Area for the Base Residual Auction for such Delivery Year.

5. Price Responsive Demand Credit Rate

(a) For the 2018/2019 through 2022/2023 Delivery Years:

(i) Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of calendar days in such Delivery Year;

(ii) Subsequent to the posting of the results from a Base Residual Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for Price Responsive Demand committed in such auction shall be (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the Price Responsive Demand load is located, in $/MW-day) times the number of calendar days in such Delivery Year times a final price uncertainty factor of 1.05;

(iii) For any additional Price Responsive Demand that seeks to commit in a Third Incremental Auction in response to a qualifying change in the final LDA load forecast, the Price Responsive Demand Credit Rate shall be the same as the rate for Price Responsive Demand that had cleared in the Base Residual Auction; and

(iv) Subsequent to the posting of the results of the Third Incremental Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for all Price Responsive Demand, shall be (the greater of (i) $20/MW-day or (ii) 0.2 times the Final Zonal Capacity Price for the Locational Deliverability Area within which the Price Responsive Demand is located) times the number of calendar days in such Delivery Year, but no greater than the Price Responsive Demand Credit Rate previously established under subsections (a)(i), (a)(ii), or (a)(iii) of this section for such Delivery Year.

(b) For the 2022/2023 Delivery Year and Subsequent Delivery Years:

(i) Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (B) $20 per MW-day) times the number of calendar days in such Delivery Year;

(ii) Subsequent to the posting of the results from a Base Residual Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for Price Responsive Demand committed in such auction shall be (the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the Price Responsive Demand is located, in $/MW-day or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year or for the Relevant

LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the Price Responsive Demand is located)] times the number of calendar days in such Delivery Year;

(iii) For any additional Price Responsive Demand that seeks to commit in a Third Incremental Auction in response to a qualifying change in the final LDA load forecast, the Price Responsive Demand Credit Rate shall be (the greater of (A) 0.5 times Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (B) $20/MW-day) times the number of calendar days in such Delivery Year; and

(iv) Subsequent to the posting of the results of the Third Incremental Auction, the Price Responsive Demand Credit Rate used for ongoing credit requirements for all Price Responsive Demand committed in such auction shall be the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the Price Responsive Demand is located or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day minus (the Capacity Performance Resource Clearing Price in such Incremental Auction for the Locational Deliverability Areas within which the Price Responsive Demand is located)] times the number of calendar days in such Delivery Year.

6. RPM Seller Credit - Additional Form of Unsecured Credit for RPM

In addition to the forms of credit specified elsewhere in this Attachment Q, RPM Seller Credit shall be available to Market Participants, but solely for purposes of satisfying RPM Auction Credit requirements. If a supplier has a history of being a net seller into PJM Markets, on average, over the past 12 months, then PJM will count as available Unsecured Credit twice the average of that Market Participant's total net monthly PJM bills over the past 12 months. This RPM Seller Credit shall be subject to the cap on available Unsecured Credit as established in section II.G.3 above.

RPM Seller Credit is calculated as a single value for each Market Participant, not separately by account, and must be designated to specific customer accounts in order to be available to satisfy RPM Auction Credit requirements that are calculated in each such customer account.

7. Credit Responsibility for Traded Planned RPM Capacity Resources

PJM may require that credit and financial responsibility for planned Capacity Resources that are traded remain with the original party (which for these purposes, means the party bearing credit responsibility for the planned Capacity Resource immediately prior to trade) unless the receiving party independently establishes consistent with this Attachment Q, that it has sufficient credit with PJM and agrees by providing written notice to PJM that it will fully assume the credit responsibility associated with the traded planned Capacity Resource.

C. Financial Transmission Right Auctions

Credit requirements described herein for FTR activity are applied separately for each customer account of a Market Participant, unless specified otherwise in this section C. FTR Participants must designate the appropriate amount of credit to each separate customer account in which any activity occurs or will occur.

1. FTR Credit Limit.

Participants must maintain their FTR Credit Limit at a level equal to or greater than their FTR Credit Requirement for each applicable account. FTR Credit Limits will be established only by a Participant providing Collateral and designating the available credit to specific accounts.

2. FTR Credit Requirement.

For each Market Participant with FTR activity, PJM shall calculate an FTR Credit Requirement. The FTR Credit Requirement shall be calculated on a portfolio basis for each Market Participant based on (a) initial margin, (b) Auction Revenue Right Credits, (c) Mark-to-Auction Value, (d) application of a 10¢ per MWh minimum value adjustment, and (e) realized gains and/or losses, as set forth in subsections (a)-(e) of this subsection, employing the formula:

Max { Max (IM – ARR – MTA, Ten Cent per Mwh Minimum) – Realized Gains and/or Losses, 0}

Where IM is the initial margin, ARR is Auction Revenue Rights Credits and MTA is the Mark-to-Auction Value. The FTR Credit Requirement may be increased to reflect any change in the value of a Market Participant's portfolio requiring an increase in Collateral as further described below.

(a) Initial Margin

Initial margin shall be calculated in accordance with the following formula:

IM = FTR Obligations IM + FTR Options IM

The model will employ a confidence interval of 99 percent.

(i) FTR Obligations IM

Initial margin values for Financial Transmission Right Obligations shall be determined utilizing a historical simulation value-at-risk methodology that calculates the size and value at risk of the applicable FTR portfolio based on a defined confidence interval and subject to a weighted aggregation method that is represented by a straight sum for long term positions and a combination of straight sum (20%) and weighted root sum of squares (80%) for balance of planning period positions.

(ii) FTR Options IM

The initial margin for Financial Transmission Right Options shall be calculated as the FTR cost minus the FTR Historical Values. FTR Historical Values shall be calculated separately for weekend on-peak, weekday on-peak, off-peak, and 24-hour FTRs for each month of the year. FTR Historical Values shall be adjusted by plus or minus ten percent for cleared counter flow or prevailing flow FTRs, respectively, in order to mitigate exposure due to uncertainty and fluctuations in actual FTR value. Historical values used in the calculation of FTR Historical Values shall be adjusted when the network simulation model utilized in PJM's economic planning process indicates that transmission congestion will decrease due to certain transmission upgrades that are in effect or planned to go into effect for the following Planning Period. The transmission upgrades to be modeled for this purpose shall only include those upgrades that, individually, or together, have 10% or more impact on the transmission congestion on an individual constraint or constraints with congestion of $5 million or more affecting a common congestion path. The adjustments to historical values shall be the dollar amount of the adjustment shown in the network simulation model.

(b) Auction Revenue Rights Credits

For a given month for which initial margin is calculated, the prorated value of any Auction Revenue Rights Credits held by a Market Participant with Financial Transmission Right Obligations shall be subtracted from the initial margin for that month. In accordance with subsection 3 below, PJM may recalculate Auction Revenue Rights Credits at any time, but shall do so no less frequently than subsequent to each annual FTR auction. If a reduction in such ARR credits at any time increases an FTR Participant's FTR Credit Requirements beyond its credit available for FTR activity, the FTR Participant must increase its Collateral or the FTR Credit Limit.

(c) Mark-to-Auction Value

A Mark-to-Auction Value shall be calculated for each Market Participant in accordance with subsection 7 below.

(d) Ten Cent (10¢) per MWh Minimum Value Adjustment

If the FTR Credit Requirement as calculated pursuant to subsections (a)-(c) above, results in a value that is less than ten cents (10¢) per MWh, the FTR Credit Requirement shall be increased to ten cents (10¢) per MWh. When calculating the portfolio MWh for this comparison, for cleared "Sell" FTRs, the MWh shall be subtracted from the portfolio total; prior to clearing, the MWh for "Sell" FTRs shall not be included in the portfolio total.

(e) Realized Gains and/or Losses

Any realized gains and/or losses resulting from the settlement of Financial Transmission Right Obligations that have not been paid out will be subtracted from the FTR Credit Requirement. A realized gain will decrease the FTR Credit Requirement (but not below $0.00), whereas a realized loss will increase the FTR Credit Requirement.

3. Rejection of FTR Bids.

Bids submitted into an auction will be rejected if the Market Participant's FTR Credit Requirement including such submitted bids would exceed the Market Participant's FTR Credit Limit, or if the Market Participant fails to provide additional Collateral as required pursuant to provisions related to mark-to-auction.

4. FTR Credit Collateral Returns.

A Market Participant may request from PJM the return of any Collateral no longer required for the FTR markets. PJM is permitted to limit the frequency of such requested Collateral returns, provided that Collateral returns shall be made by PJM at least once per calendar quarter, if requested by a Market Participant.

5. Credit Responsibility for Bilateral Transfers of FTRs.

PJM may require that credit responsibility associated with an FTR bilaterally transferred to a new Market Participant remain with the original party (which for these purposes, means the party bearing credit responsibility for the FTR immediately prior to bilateral transfer) unless and until the receiving party independently establishes, consistent with this Attachment Q, sufficient credit with PJM and agrees through confirmation of the bilateral transfer in PJM's FTR reporting tool that it will meet in full the credit requirements associated with the transferred FTR.

6. FTR Administrative Charge Credit Requirement

In addition to any other credit requirements, PJM may apply a credit requirement to cover the maximum administrative fees that may be charged to a Market Participant for its bids and offers.

7. Mark-to-Auction

A Mark-to-Auction Value shall be calculated separately for each customer account of a Market Participant. For each such customer account, the Mark-to-Auction Value shall be a single number equal to the sum, over all months remaining in the applicable FTR period and for all cleared FTRs in the customer account, of the most recently available cleared auction price applicable to the FTR minus the original transaction price of the FTR, multiplied by the transacted quantity.

The FTR Credit Requirement, as otherwise described above, shall be increased when the Mark-to-Auction Value is negative and decreased when the Mark-to-Auction Value is positive. The increase shall equal the absolute value of the negative Mark-to-Auction Value less the value of ARR credits that are held in the customer account and have not been used to reduce the FTR Credit Requirement prior to application of the Mark-to-Auction Value. PJM shall recalculate ARR credits held by each Market Participant after each annual FTR auction and may also recalculate such ARR credits at any other additional time intervals it deems appropriate. Application of the Mark-to-Auction Value, including the effect from ARR application, shall not decrease the FTR Credit Requirement below the Ten Cent (10¢) per MWh Minimum.

For Market Participant customer accounts for which FTR bids have been submitted into the current FTR auction, if the Market Participant's FTR Credit Requirement exceeds its credit available for the Market Participant's portfolio of FTRs in the tentative cleared solution for an FTR auction (or auction round), PJM shall issue a Collateral Call to the Market Participant, and the Market Participant must fulfill such demand before 4:00 p.m. Eastern Prevailing Time on the following Business Day. If a Market Participant does not timely satisfy such Collateral Call, PJM shall, in coordination with PJM, cause the removal of all of that Market Participant's bids in that FTR auction (or auction round), submitted from such Market Participant's customer account, and a new cleared solution shall be calculated for the FTR auction (or auction round).

If necessary, PJM shall repeat the auction clearing calculation. PJM shall repeat these mark-to-auction calculations subsequent to any secondary clearing calculation, and PJM shall require affected Market Participants to establish additional credit.

Subsequent to final clearing of an FTR auction or an annual FTR auction round, PJM shall recalculate the FTR Credit Requirement for all FTR portfolios, and, as applicable, issue to each Market Participant a request for Collateral for the total amount by which the FTR Credit Requirement exceeds the credit allocated in any of the Market Participant's accounts. The Market Participant must fulfill such demand by 4:00 p.m. Eastern Prevailing Time on the following Business Day.

If the request for Collateral is not satisfied within the applicable cure period referenced in Operating Agreement, section 15, then such Market Participant shall be restricted in all of its credit-screened transactions. Specifically, such Market Participant may not engage in any Virtual Transactions or Export Transactions, or participate in RPM Auctions or other RPM activity. Such Market Participant may engage only in the selling of open FTR positions, either in FTR auctions or bilaterally, provided such sales would reduce the Market Participant's FTR Credit Requirements. PJM shall not return any Collateral to such Market Participant, and no payment shall be due or payable to such Market Participant, until its credit shortfall is remedied. Market Participant shall allocate any excess or unallocated Collateral to any of its account in which there is a credit shortfall. Market Participants may remedy their credit shortfall at any time through provision of sufficient Collateral.

If a Market Participant fails to satisfy a request for Collateral for two consecutive auctions of overlapping periods, e.g. two balance of Planning Period auctions, an annual FTR auction and a balance of Planning Period auction, or two long term FTR auctions, (for this purpose the four rounds of an annual FTR auction shall be considered a single auction), the Market Participant shall be declared in default of this Attachment Q.

VII. PEAK MARKET ACTIVITY AND WORKING CREDIT LIMIT

A. Peak Market Activity Credit Requirement

PJM shall calculate a Peak Market Activity credit requirement for each Participant. Each Participant must maintain sufficient Unsecured Credit Allowance and/or Collateral, as applicable, and subject to the provisions herein, to satisfy its Peak Market Activity credit requirement.

Peak Market Activity for Participants will be determined weekly, utilizing an initial Peak Market Activity, as explained in this section VII.A below. Peak Market Activity shall be the greater of the initial Peak Market Activity, or the greatest amount invoiced for the Participant's transaction activity for all PJM Markets and services in the rolling past one, two, three or four-week period.

However, Peak Market Activity shall not exceed the greatest amount invoiced for the Participant’s transaction activity for all PJM Markets and services in any rolling one, two or three-week period in the prior 52 weeks.

Peak Market Activity shall exclude FTR Net Activity, Virtual Transactions Net Activity, and Export Transactions Net Activity.

Peak Market Activity = min [max [initial Peak Market Activity, max [greatest amount invoiced for transaction activity for the rolling past one, two, three, or four-week period]], max [greatest amount invoiced for transaction activity for any rolling one, two or three-week period in the prior 52 weeks]

When calculating Peak Market Activity, PJM may attribute credits for Regulation service to the days on which they were accrued, rather than including them in the month-end invoice.

The initial Peak Market Activity for Applicants will be determined by PJM based on a review of an estimate of their transactional activity for all PJM Markets and services over the next 52 weeks, which the Applicant shall provide to PJM.

The initial Peak Market Activity for Market Participants and Transmission Customers, calculated weekly upon issuance of the weekly invoice, shall be the three-week average of all non-zero invoice totals over the previous 52 weeks.

Prepayments shall not affect Peak Market Activity unless otherwise agreed to in writing pursuant to this Attachment Q.

Peak Market Activity calculations shall take into account reductions of invoice values effectuated by early payments which are applied to reduce a Participant’s Peak Market Activity as contemplated by other terms of this Attachment Q; provided that the initial Peak Market Activity shall not be less than the average value calculated using the weeks for which no early payment was made.

A Participant may reduce its Collateral requirement by agreeing in writing (in a form acceptable to PJM) to make additional payments, including prepayments, as and when necessary to ensure that such Participant’s Total Net Obligation at no time exceeds such reduced Collateral requirement.

In the event that the Peak Market Activity Shortfall exceeds or equals the Minimum Exposure, the prior week’s Peak Market Activity credit requirement will be increased by an amount equal to n * the Minimum Transfer Amount, with n being the integer that will cause the current week’s Peak Market Activity credit requirement to be greater than or equal to the Participant’s current Peak Market Activity but less than the Participant’s current Peak Market Activity plus the Minimum Transfer Amount. For the avoidance of doubt, if the Peak Market Activity Shortfall is less than the Minimum Exposure, the current week’s Peak Market Activity credit requirement will remain the same as the prior week’s Peak Market Activity credit requirement.

In the event that the Peak Market Activity Surplus exceeds or equals the Minimum Transfer Amount, the prior week's Peak Market Activity credit requirement will be decreased by an amount equal to n * the Minimum Transfer Amount, with n being the integer that will cause the current week's Peak Market Activity credit requirement to be greater than or equal to the Participant's current Peak Market Activity but less than the Participant's current Peak Market Activity plus the Minimum Transfer Amount. For the avoidance of doubt, if the Peak Market Activity Surplus is less than the Minimum Transfer Amount, the current week's Peak Market Activity credit requirement will remain the same as the prior week's Peak Market Activity credit requirement.

In the event that there is neither a Peak Market Activity Shortfall nor a Peak Market Activity Surplus, then the current week's Peak Market Activity credit requirement is the same as the prior week's Peak Market Activity credit requirement.

PJM may, at its discretion, adjust a Participant's Peak Market Activity credit requirement if PJM determines that the Peak Market Activity is not representative of such Participant's expected activity, as a consequence of known, measurable, and sustained changes. Such changes may include, but shall not be limited to when a Participant makes PJM aware of federal, state or local law that could affect the allocation of charges or credits from a Participant to another party, the loss (without replacement) of short-term load contracts, when such contracts had terms of three months or more and were acquired through state-sponsored retail load programs, but shall not include short-term buying and selling activities.

PJM may waive the credit requirements for a Participant that has no outstanding transactions and agrees in writing that it shall not, after the date of such agreement, incur obligations under any of the Agreements. Such entity's access to all electronic transaction systems administered by PJM shall be terminated.

A Participant receiving unsecured credit may make early payments up to thirteen (13) times in a rolling 52-week period in order to reduce its Peak Market Activity for credit requirement purposes. Imputed Peak Market Activity reductions for credit purposes will be applied to the billing period for which the payment was received. Payments used as the basis for such reductions must be received prior to issuance or posting of the invoice for the relevant billing period. The imputed Peak Market Activity reduction attributed to any payment may not exceed the amount of Unsecured Credit for which the Participant is eligible.

B. Working Credit Limit

PJM will establish a Working Credit Limit for each Participant against which its Total Net Obligation will be monitored.

If a Participant's Total Net Obligation approaches its Working Credit Limit, PJM may require the Participant to make an advance payment or increase its Collateral in order to maintain its Total Net Obligation below its Working Credit Limit. Except as explicitly provided herein, advance payments shall not serve to reduce the Participant's Peak Market Activity for the purpose of calculating credit requirements.

> Example: After ten (10) calendar days, and with five (5) calendar days remaining before the bill is due to be paid, a Participant approaches its $4.0 million Working Credit Limit. PJM may require a prepayment of $2.0 million in order that the Total Net Obligation will not exceed the Working Credit Limit.

If a Participant exceeds its Working Credit Limit or is required to make advance payments more than ten times during a 52-week period, PJM may require Collateral in an amount as may be deemed reasonably necessary to support its Total Net Obligation.

When calculating Total Net Obligation, PJM may attribute credits for Regulation service to the days on which they were accrued, rather than including them in the month-end invoice.

VIII. SUSPENSION OR LIMITATION ON MARKET PARTICIPATION

If PJM determines that a Participant presents an unreasonable credit risk as determined pursuant to initial or ongoing risk evaluations, as described in section II above, or in the case of any other event which, after notice, lapse of time, or both, would result in an Event of Default, PJM will take steps to mitigate the exposure of any PJM Markets, which may include, but is not limited to, requiring Collateral, additional Collateral or Restricted Collateral or suspending or limiting the Market Participant's ability to participate in the PJM Markets commensurate to the risk to any PJM Markets.

If a Participant fails to reduce or eliminate any unreasonable credit risks to PJM's satisfaction within the applicable cure period including without limitation by posting Collateral, additional Collateral or Restricted Collateral, PJM may treat such failure as an Event of Default.

Notwithstanding the foregoing, a Participant that transacts in FTRs will be eligible to request that PJM exempt or exclude FTR transactions of such Participant from the effect of any such limitations on market activity established by PJM, and PJM may but shall not be required to so exempt or exclude, any FTR transactions that the Participant reasonably demonstrates to PJM it has entered into to "hedge or mitigate commercial risk" arising from its transactions in the PJM Interchange Energy Market that are intended to result in the actual flow of physical energy or ancillary services in the PJM Region, as the phrase "hedge or mitigate commercial risks" is defined under the CFTC's regulations defining the end-user exception to clearing set forth in 17 C.F.R. §50.50(c).

IX. REMEDIES FOR CREDIT BREACH, FINANCIAL DEFAULT OR CREDIT SUPPORT DEFAULT; REMEDIES FOR EVENTS OF DEFAULT; GENERAL BANKRUPTCY PROVISIONS

If PJM determines that a Market Participant is in Credit Breach, or that a Financial Default or Credit Support Default exists, PJM may issue to the Market Participant a breach notice and/or a Collateral Call or demand for additional documentation or assurances. At such time, PJM may also suspend payments of any amounts due to the Participant and limit, restrict or rescind the Market Participant's privileges to participate in any or all PJM Markets under the Agreements during any such cure period. Failure to remedy the Credit Breach, Financial Default or to satisfy a Collateral Call or demand for additional documentation or assurances within the applicable cure period described in Operating Agreement, section 15.1.5, shall constitute an Event of

Default. If a Participant fails to meet the requirements of this Attachment Q, but then remedies the Credit Breach, Financial Default or Credit Support Default, or satisfies a Collateral Call or demand for additional documentation or assurances within the applicable cure period, then the Participant shall be deemed to again be in compliance with this Attachment Q, so long as no other Credit Breach, Financial Default, Credit Support Default or Collateral Call or demand for additional documentation or assurances has occurred and is continuing.

Only one cure period shall apply to a single event giving rise to a Credit Breach, Financial Default or Credit Support Default. Application of Collateral towards a Financial Default, Credit Breach or Credit Support Breach shall not be considered a cure of such Credit Breach, Financial Default or Credit Support Default unless the Participant is determined by PJM to be in full compliance with all requirements of this Attachment Q after such application.

When an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing, PJM may take such actions as may be required or permitted under the Agreements to protect the PJM Markets and the PJM Members, including but not limited to (a) suspension and/or termination of the Participant's ongoing Transmission Service, (b) limitation, suspension and/or termination of participation in any PJM Markets, (c) taking all necessary steps to address the Market Participant's market portfolio in accordance with the provisions of the Operating Agreement and PJM Tariff, including, but not limited to, allowing such portfolio's positions to go to settlement, liquidating or otherwise resolving such portfolio positions, exercising judgment in the manner in which this is achieved in any PJM Markets. PJM may permit a defaulting Market Participant to continue to participate in PJM Markets: (a) in support of grid reliability, (b) when such Market Participant is a net market seller, (c) when such Market Participant has the ability to post collateral, or (d) to enable certain customers to continue to receive service prior to PJM receiving regulatory or legal approval to terminate.

When an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing, PJM also has the immediate right to liquidate all or a portion of a Participant's Collateral at its discretion to satisfy Total Net Obligations to PJM under this Attachment Q or one or more of the Agreements. No remedy for an Event of Default is or shall be deemed to be exclusive of any other available remedy or remedies by contract or under applicable laws and regulations. Each such remedy shall be distinct, separate and cumulative, shall not be deemed inconsistent with or in exclusion of any other available remedy, and shall be in addition to and separate and distinct from every other remedy.

When an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing, PJM may continue to retain all payments due to a Participant as a cash security for all such Participant's obligations under the Agreements (regardless of any restrictions placed on such Participant's use of Collateral for any account, market activity or capitalization purpose); provided, however, that an Event of Default will not be deemed cured or no longer continuing because PJM is retaining amounts due the Participant, or because PJM has not yet applied Collateral or credit support to any amounts due PJM, unless PJM determines that the Participant has again satisfied all the Collateral requirements and application requirements as a new Applicant for participation in the PJM Markets, and consistent with the requirements and limitations of Operating Agreement, section 15.

In Event of Default by a Participant, PJM may exercise any remedy or action allowed or prescribed by this Attachment Q immediately or following investigation and determination of an orderly exercise of such remedy or action. Delay in exercising any allowed remedy or action shall not preclude PJM from exercising such remedy or action at a later time.

PJM may hold a defaulting Participant's Collateral for as long as such party's positions exist and consistent with this Attachment Q, in order to protect the PJM Markets and PJM's membership, and minimize or mitigate the impacts or potential impacts or risks associated with such Event of Default when an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing.

PJM may apply towards an ongoing Event of Default any amounts that are held or later become available or due to the defaulting Participant through PJM's markets and systems.

In order to cover the Participant's Obligations, PJM may hold a Participant's Collateral indefinitely and specifically through the end of the billing period which includes the 90th day following the last day a Participant had activity, open positions, or accruing obligations (other than reconciliations and true-ups), until such Participant has satisfactorily paid any obligations invoiced through such period and until PJM determines that the Participant's positions represent no risk exposure to the PJM Markets or the PJM Members. Obligations incurred or accrued through such period shall survive any withdrawal from PJM. When an Event of Default under this Attachment Q or one or more of the Agreements has occurred and is continuing, PJM may apply any Collateral to such Participant's Obligations, even if Participant had previously announced and effected its withdrawal from PJM.

To protect PJM Members and PJM Markets from loss and harm due to uncertainty and delay which may be created upon a Participant's bankruptcy, in the event a Participant becomes a debtor under the United States Bankruptcy Code, 11 U.S.C. §§ 101-1532 (the "Bankruptcy Code"), whether voluntarily or involuntarily, the Participant should upon the commencement of the bankruptcy case immediately seek through a "first day" motion or motions, to the extent appropriate under the circumstances to provide PJM with prompt clarity as to its rights and treatment, the entry of an order of the bankruptcy court: (i) authorizing and directing the Participant to (a) make prompt and full payment of all pre-petition Obligations to PJM; and (b) fulfill all obligations under the Tariff and other Agreements in the ordinary course of business, including but not limited to deposit of additional Collateral post-petition; (ii) authorizing PJM to (x) require, hold and apply Collateral in accordance with this Attachment Q and (y) exercise setoff and recoupment to the fullest extent provided under the Tariff and other Agreements, and applicable nonbankruptcy law; and (iii) confirming the status of Agreements as a "forward contract", "swap agreement", or "master netting agreement" under the Bankruptcy Code, as applicable.

In the event that a debtor Participant fails to file such a "first day" motion within one (1) Business Day of the commencement of the bankruptcy case, or the bankruptcy court does not enter an order granting the relief requested in such "first day" motion within seven (7) days thereof, PJM may file a motion for relief from the automatic stay under section 362(d) of the

Bankruptcy Code, citing the lack of prompt clarity as "cause" thereunder, to the extent necessary to permit PJM to exercise any rights and remedies under the Tariff and other Agreements.

X. FTR TRANSACTIONS AS FORWARD CONTRACTS AND/OR SWAP AGREEMENTS UNDER THE BANKRUPTCY CODE

Under the terms of the Tariff, PJM Settlement is the counterparty to all transactions in PJM Markets, including but not limited to all FTR transactions, other than (i) any bilateral transactions between Participants, or (ii) with respect to self-supplied or self-scheduled transactions reported to the Office of the Interconnection. Pursuant to the "Final Order in Response to a Petition From Certain Independent System Operators and Regional Transmission Organizations To Exempt Specified Transactions Authorized by a Tariff or Protocol Approved by the Federal Energy Regulatory Commission or the Public Utility Commission of Texas From Certain Provisions of the Commodity Exchange Act Pursuant to the Authority Provided in the Act" 78 Fed. Reg. 19880 (April 2, 2013) (the "CFTC RTO/ISO Order"), the Commodity Futures Trading Commission (the "CFTC") exempts transactions offered or entered into in a market administered by PJM pursuant to the Tariff, including but not limited to FTR transactions, from the provisions of the Commodity Exchange Act and the CFTC's rules applicable to "swaps," with the exception of the CFTC's general anti-fraud and anti-manipulation authority and scienter-based prohibitions.

Notwithstanding the CFTC RTO/ISO Order, all FTR transactions constitute "forward contracts" and/or "swap agreements" within the meaning of the Bankruptcy Code, and PJM shall be deemed to be a "forward contract merchant" and/or a "swap participant" within the meaning of the Bankruptcy Code for purposes of FTR transactions.

Pursuant to this Attachment Q and other provisions of the Agreements, PJM already has, and shall continue to have, the following rights (among other rights) with respect to a Market Participant's Event of Default under those documents: (a) the right to terminate, liquidate or otherwise resolve any FTR transaction or position held by that Market Participant, including by allowing such position to go to settlement; (b) the right to immediately proceed against any Collateral and additional financial assurance provided by that Market Participant; (c) the right to set off or recoup any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement, or similar agreement against any amounts due and owing by that Market Participant pursuant to any forward contract, swap agreement, or similar agreement, such arrangement to constitute a "master netting agreement" within the meaning of the Bankruptcy Code; and (d) the right to suspend or limit that Market Participant from entering into further FTR transactions.

For the avoidance of doubt, upon the commencement of a voluntary or involuntary proceeding for a Market Participant under the Bankruptcy Code, and without limiting any other rights of PJM or obligations of any Market Participant under the Tariff (including this Attachment Q) or other Agreements, PJM may exercise any of its rights against such Market Participant, including, without limitation (1) the right to terminate, liquidate or otherwise resolve any FTR transaction or position held by that Market Participant, including by allowing such position to go to settlement, (2) the right to immediately proceed against any Collateral and additional financial assurance provided by that Market Participant, (3) the right to set off or recoup any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement and/or master netting agreement against any amounts due and owing by that Market Participant with respect to an FTR transaction including as a result of the actions taken by PJM pursuant to (1) above, and (4) the right to suspend or limit that Market Participant from entering into future FTR transactions.

For purposes of the Bankruptcy Code, all transactions, including but not limited to FTR transactions, between PJM, on the one hand, and a Market Participant, on the other hand, are intended to be, and are, part of a single integrated agreement, and together with the Agreements constitute a “master netting agreement.”

Attachment Q
Appendix 1

PJM MINIMUM PARTICIPATION CRITERIA
ANNUAL OFFICER CERTIFICATION FORM

Participant Name: ____ ("Participant")

I, ____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. and PJMSettlement, Inc. ("PJMSettlement") are relying on this certification as evidence that Participant meets the minimum requirements set forth in the PJM Open Access Transmission Tariff ("PJM Tariff"), Attachment Q hereby certify that I have full authority to represent on behalf of Participant and further represent as follows, as evidenced by my initialing each representation in the space provided below:

1. All employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Amended and Restated Operating Agreement ("PJM Operating Agreement") on behalf of the Participant have received appropriate training and are authorized to transact on behalf of Participant. As used in this representation, the term "appropriate" as used with respect to training means training that is (i) comparable to generally accepted practices in the energy trading industry, and (ii) commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the participant.__________

2. Participant has written risk management policies, procedures, and controls, approved by Participant's independent risk management function and applicable to transactions in any PJM Markets in which it participates and for which employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Operating Agreement have been trained, that provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Participant is exposed, including, but not limited to credit risks, liquidity risks and market risks. As used in this representation, a Participant's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Participant's trading functions, such as a risk management committee, a risk officer, a Participant's board or board committee, or a board or committee of the Participant's parent company.

    a. Participant is providing to PJM or PJMSettlement, in accordance with Tariff, Attachment Q, section III, with this Annual Officer Certification Form, a copy of its current governing risk management policies, procedures and controls applicable to its activities in any PJM Markets pursuant to Attachment Q or because there have been substantive changes made to such policies, procedures and controls applicable to its market activities since they were last provided to PJM.__________

    b. If the risk management policies, procedures and controls applicable to Participant's market activities submitted to PJM or PJMSettlement were submitted prior to the current certification, Participant certifies that no substantive changes have been made to such policies, procedures and controls applicable to its market activities since such submission.__________

3. An FTR Participant must make either the following 3.a. or 3.b. additional representations, evidenced by the undersigned officer initialing either the one 3.a. representation or the four 3.b. representations in the spaces provided below:

   a. Participant transacts in PJM's FTR markets with the sole intent to hedge congestion risk in connection with either obligations Participant has to serve load or rights Participant has to generate electricity in the PJM Region ("physical transactions") and monitors all of the Participant's FTR market activity to endeavor to ensure that its FTR positions, considering both the size and pathways of the positions, are either generally proportionate to or generally do not exceed the Participant's physical transactions, and remain generally consistent with the Participant's intention to hedge its physical transactions.__________

   b. On no less than a weekly basis, Participant values its FTR positions and engages in a probabilistic assessment of the hypothetical risk of such positions using analytically based methodologies, predicated on the use of industry accepted valuation methodologies.__________

   Such valuation and risk assessment functions are performed either by persons within Participant's organization independent from those trading in PJM's FTR markets or by an outside firm qualified and with expertise in this area of risk management.__________

   Having valued its FTR positions and quantified their hypothetical risks, Participant applies its written policies, procedures and controls to limit its risks using industry recognized practices, such as value-at-risk limitations, concentration limits, or other controls designed to prevent Participant from purposefully or unintentionally taking on risk that is not commensurate or proportional to Participant's financial capability to manage such risk.__________

   Exceptions to Participant's written risk policies, procedures and controls applicable to Participant's FTR positions are documented and explain a reasoned basis for the granting of any exception.__________

4. Participant has appropriate personnel resources, operating procedures and technical abilities to promptly and effectively respond to all PJM and PJMSettlement communications and directions.__________

5. Participant has demonstrated compliance with the Minimum Capitalization criteria set forth in Tariff, Attachment Q that are applicable to any PJM Markets in which Participant transacts, and is not aware of any change having occurred or being imminent that would invalidate such compliance.__________

6. All Participants must certify and initial in at least one of the five sections below:

a. I certify that Participant qualifies as an “appropriate person” as that term is defined under section 4(c)(3), or successor provision, of the Commodity Exchange Act or an “eligible contract participant” as that term is defined under section 1a(18), or successor provision, of the Commodity Exchange Act. I certify that Participant will cease transacting in any PJM Markets and notify PJM and PJMSettlement immediately if Participant no longer qualifies as an “appropriate person” or “eligible contract participant.”__________

If providing audited financial statements, which shall be in US GAAP format or any other format acceptable to PJM, to support Participant’s certification of qualification as an “appropriate person:”

I certify, to the best of my knowledge and belief, that the audited financial statements provided to PJM and/or PJMSettlement present fairly, pursuant to such disclosures in such audited financial statements, the financial position of Participant as of the date of those audited financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $5 million total asset levels reflected in these audited financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

If not providing audited financial statements to support Participant’s certification of qualification as an “appropriate person,” Participant certifies that they qualify as an “appropriate person” under one of the entities defined in section 4(c)(3)(A)-(J) of the Commodities Exchange Act. __________

If providing audited financial statements, which shall be in US GAAP format or any other format acceptable to PJM, to support Participant’s certification of qualification as an “eligible contract participant:”

I certify, to the best of my knowledge and belief, that the audited financial statements provided to PJM and/or PJMSettlement present fairly, pursuant to such disclosures in such audited financial statements, the financial position of Participant as of the date of those audited financial statements. Further, I certify that Participant continues to maintain the minimum $1 million total net worth and/or $10 million total asset levels reflected in these audited financial statements as of the date of this certification. I acknowledge that both PJM and PJMSettlement are relying upon my certification to maintain compliance with federal regulatory requirements.__________

If not providing audited financial statements to support Participant’s certification of qualification as an “eligible contract participant,” Participant certifies that they qualify as an “eligible contract participant” under one of the entities defined in section 1a(18)(A) of the Commodities Exchange Act. __________

b. I certify that Participant has provided an unlimited Corporate Guaranty in a form acceptable to PJM as described in Tariff, Attachment Q, section III.D from an issuer that has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty. I also certify, to the best of my knowledge and belief, that the audited financial statements provided to PJM and/or PJMSettlement present fairly, pursuant to such disclosures in such audited financial statements, the financial position of the issuer as of the date of those audited financial statements. Further, I certify that Participant will cease transacting PJM's Markets and notify PJM and PJMSettlement immediately if issuer of the unlimited Corporate Guaranty for Participant no longer has at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty.__________

   I certify that the issuer of the unlimited Corporate Guaranty to Participant continues to have at least $1 million of total net worth or $5 million of total assets per Participant for which the issuer has issued an unlimited Corporate Guaranty. I acknowledge that PJM and PJMSettlement are relying upon my certifications to maintain compliance with federal regulatory requirements.__________

c. I certify that Participant fulfills the eligibility requirements of the Commodity Futures Trading Commission exemption order (78 F.R. 19880 – April 2, 2013) by being in the business of at least one of the following in the PJM Region as indicated below (initial those applicable):

   1. Generating electric energy, including Participants that resell physical energy acquired from an entity generating electric energy:__________

   2. Transmitting electric energy:__________

   3. Distributing electric energy delivered under Point-to-Point or Network Integration Transmission Service, including scheduled import, export and wheel through transactions:__________

   4. Other electric energy services that are necessary to support the reliable operation of the transmission system:__________

      Description only if c(4) is initialed:

      ____

   Further, I certify that Participant will cease transacting in any PJM Markets and notify PJM and PJMSettlement immediately if Participant no longer performs at least one of the functions noted above in the PJM Region. I acknowledge that PJM and PJMSettlement are relying on my certification to maintain compliance with federal energy regulatory requirements.__________

d. I certify that Participant has provided a Letter of Credit of $5 million or more to PJM or PJMSettlement in a form acceptable to PJM and/or PJMSettlement as described in Tariff, Attachment Q, section V.B that the Participant acknowledges cannot be utilized to meet its credit requirements to PJM and PJMSettlement. I acknowledge that PJM and PJMSettlement are relying on the provision of this letter of credit and my certification to maintain compliance with federal regulatory requirements.__________

e. I certify that Participant has provided a surety bond of $5 million or more to PJM or PJMSettlement in a form acceptable to PJM and/or PJMSettlement as described in Tariff, Attachment Q, section V.D. that the Participant acknowledges cannot be utilized to meet its credit requirements to PJM and PJMSettlement. I acknowledge that PJM and PJMSettlement are relying on the provision of this surety bond and my certification to maintain compliance with federal regulatory requirements. __________

7. I acknowledge that I have read and understood the provisions of Tariff, Attachment Q applicable to Participant's business in any PJM Markets, including those provisions describing PJM's Minimum Participation Requirements and the enforcement actions available to PJM and PJMSettlement of a Participant not satisfying those requirements. I acknowledge that the information provided herein is true and accurate to the best of my belief and knowledge after due investigation. In addition, by signing this certification, I acknowledge the potential consequences of making incomplete or false statements in this Certification.__________

Date: ____________________________ ____________________________________

Participant (Signature)

Print Name: ____________________________________

Title: ____________________________________

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction;

d) Calculating the EFORd for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction;

e) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

f) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

g) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

h) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with Operating Agreement, section 18.17, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Tariff, Attachment DD.

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the minimum offer price rule set forth in Tariff, Attachment DD, section 5.14 (h-2). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Tariff, Attachment DD, section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.5A Capacity Resource Types

(a) Capacity Performance Resources

Capacity Performance Resources are Capacity Resources which, to the extent such resources cleared in a Reliability Pricing Model Auction or are otherwise committed as a Capacity Resource, are obligated to deliver energy during the relevant Delivery Year as scheduled and/or dispatched by the Office of Interconnection during the Performance Assessment Intervals. As further detailed in Tariff, Attachment DD, section 10A, Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d). Subject to 5.5A(a)(i), the following types of Capacity Resources are eligible to submit a Sell Offer as a Capacity Performance Resource: internal or external Generation Capacity Resources; Annual Demand Resources; Capacity Storage Resources; Annual Energy Efficiency Resources; and Qualifying Transmission Upgrades. To the extent the underlying Capacity Resource is an external Generation Capacity Resource, such resource must meet, to the extent subsection (b) or (c) of this section is applicable to offers from such resource, meet the applicable requirements of such subsection, and if neither subsection (b) or (c) is applicable, then offers from such resource must the criteria for obtaining an exception to the Capacity Import Limit as contained in RAA, Article 1.

(i) Process for Support and Review of Capacity Performance Resource Offers

A. The Capacity Market Seller shall provide to the Office of the Interconnection and the Market Monitoring Unit, upon their request, all supporting data and information requested by either the Office of the Interconnection or the Market Monitoring Unit to evaluate whether the underlying Capacity Resource can meet the operational and performance requirements of Capacity Performance Resources. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes.

B. The Office of the Interconnection and the Market Monitoring Unit shall review any requested supporting data and information, and the Office of the Interconnection, considering advice and recommendation from the Market Monitoring Unit, shall reject a request for a resource to offer as a Capacity Performance Resource if the Capacity Market Seller does not demonstrate that it can reasonably be expected to meet its Capacity Performance obligations consistent with the resource's offer by the relevant Delivery Year. The Office of Interconnection shall provide its determination to reject eligibility of the resource as a Capacity Performance Resource, and notify the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(b) Offers from External Generation Capacity Resources for the 2020/2021 Delivery Year and Subsequent Delivery Years—General Rule

For the 2020/2021 Delivery Year and any subsequent Delivery Year and for Capacity Performance Resource Sell Offers in any RPM Auction conducted for the 2018/2019 Delivery Year or 2019/2020 Delivery Year after May 9, 2017, unless excepted pursuant to subsection (c) below, a Capacity Market Seller may submit a Sell Offer for an external Generation Capacity Resource in an RPM Auction if the Capacity Market Seller demonstrates to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) The Capacity Market Seller has obtained a determination that the Pseudo-Tie required for its external Generation Capacity Resource is feasible, including (without limitation) that such Pseudo-Tie meets the following requirements:

(A) the external Generation Capacity Resource must have a minimum Electrical Distance impedance equal to or less than 0.065 p.u.; or is within one station of a transmission bus that has a minimum Electrical Distance impedance equal to or less than 0.065 p.u. With regard to this Electrical Distance requirement, the Office of the Interconnection shall:

(1) post on its website the material assumptions, applicable to all tested generators, implemented in the modeling software used to conduct the Electrical Distance analysis (e.g., the general process used to define the facilities included in the Electrical Distance requirement and analysis for each Pseudo-Tie applicant);

(2) upon request by an applicant for a Pseudo-Tie, provide that applicant a copy of the results of the Electrical Distance analysis conducted by the Office of the Interconnection for the specific Pseudo-Tie requested by the applicant, as well as related work papers; and

(3) upon request by an applicant for a Pseudo-Tie, meet with that applicant to discuss specific modeling assumptions and the results of the Electrical Distance analysis for the specific Pseudo-Tie requested by that applicant;

(B) at least one generation resource that has a historic economic minimum offer lower than its historic economic maximum offer, located inside the metered boundaries of the PJM Region, has a minimum flow distribution impact of 1.5 percent on each eligible coordinated flowgate resulting from such Pseudo-Tie. With regard to this requirement, the Office of the Interconnection shall:

(1) post on its website the material assumptions, applicable to all tested generators, that have been implemented in the modeling software used to conduct the analysis to determine whether the requirement has been met (e.g., the definitions of the sink and source used in the market-to-

market analysis and the definition of eligible coordinated flowgates as applicable to the requirement);

(2) upon request by an applicant for a Pseudo-Tie, provide that applicant a copy of the results of the market-to-market flowgate analysis conducted by the Office of the Interconnection for the specific Pseudo-Tie requested by the applicant, as well as related work papers; and

(3) upon request by an applicant for a Pseudo-Tie, meet with that applicant to discuss specific modeling assumptions and the results of the market-to-market flowgate analysis conducted for the specific Pseudo-Tie requested by that applicant;

(C) each external entity with which PJM may be required to coordinate flowgates under an agreed congestion management process maintains a network model that produces results for such flowgates that are within two percent of the results produced by the PJM network model for such flowgates;

(D) the Capacity Market Seller has secured written acknowledgement from the external Balancing Authority Areas that such Pseudo-Tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM.

and the Capacity Market Seller has committed in writing that it will take all steps necessary to implement such Pseudo-Tie prior to the start of the relevant Delivery Year;

(ii) it has, for transmission outside PJM, obtained long-term firm point-to-point transmission service (evaluated for deliverability from the unit-specific physical location of the resource to PJM load pursuant to a study that is reviewed and approved by PJM in accordance with PJM deliverability criteria to ensure uniformity for internal and external resource deliverability requirements), with rollover rights for the term of the transmission service that is confirmed by the Balancing Authority for the Balancing Authority Area where such resource is geographically located; and, as to transmission within PJM, has obtained Network External Designated Transmission Service; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions.

A Capacity Market Seller that satisfies the above requirements with respect to an external Generation Capacity Resource Sell Offer submitted in an RPM Auction for a Delivery Year shall be required to demonstrate satisfaction of such requirements for any Sell Offer with respect to such resource submitted in an RPM Auction for any subsequent Delivery Year, including, without limitation, demonstration that the required external transmission service continues to satisfy PJM's deliverability standards.

(c) Offers from external Generation Capacity Resources for the 2020/2021 Delivery Year and Subsequent Delivery Years—Exception.

A Capacity Market Seller of a Prior CIL Exception External Resource may continue to submit Sell Offers for such resource for any RPM Auction for any Delivery Year up to and including the 2021/2022 Delivery Year (or, solely for any such resource that is (1) owned by a Load Serving Entity and used to self-supply (under arrangements initiated before June 1, 2016, with a duration of at least ten years) such entity's PJM Region load or (2) the subject of a contract for energy or capacity or equivalent written agreement entered into on or before June 1, 2016 for a term of ten years or longer with a purchaser that is an internal PJM load customer, for any Delivery Year during the life of such resource for subparagraph (1) or for the term of the agreement under subparagraph (2)) so long as it continues to comply with all conditions on the grant of its exception to the Capacity Import Limit, subject to the following additional conditions:

(i) for any Delivery Year, beginning with the 2017/2018 Delivery Year, for which such Prior CIL Exception External Resource has cleared an RPM Auction, PJM may in its sole judgment determine that the resource is not Operationally Deliverable for such Delivery Year because it does not satisfy the requirements of subsection (b). If PJM determines a Prior CIL Exception External Resource is not Operationally Deliverable for a Delivery Year, it must notify the Capacity Market Seller of its determination by no later than October 1 immediately preceding such Delivery Year. After receiving such notice, the Capacity Market Seller may elect to:

(A) take the necessary actions to make the Prior CIL Exception External Resource Operationally Deliverable, in PJM's sole judgment, prior to the beginning of such Delivery Year, provided that PJM will, if transmission upgrades are required to make such resource Operationally Deliverable, facilitate the performance of transmission studies and otherwise cooperate with the external Transmission Provider of the system on which such upgrades are required to identify the upgrades required to meet PJM's deliverability standards;

(B) be relieved of its capacity obligation for such Delivery Year by providing written notice of such election to the Office of the Interconnection no later than seven (7) days prior to the posting of planning parameters for the Third Incremental Auction for such Delivery Year as PJM will procure the replacement capacity in the Third Incremental Auction in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii), with no entitlement to any capacity revenues based on such resource, with no requirement to seek replacement for such capacity for such Delivery Year, with no penalty for non-performance or lack of commitment for such Delivery Year, and with no further must-offer obligation that would otherwise arise solely from clearing such capacity for such Delivery Year; or

(C) procure, by purchase or otherwise, replacement in a sufficient quantity to replace the capacity that would have been provided by the Prior CIL Exception External Resource but for PJM's determination that such resource is not Operationally Deliverable.

(ii) Such Capacity Market Seller's continued ability to offer such resource under this exception is conditioned on external Transmission Providers continuing to honor the firm status of the Capacity Market Seller's transmission service for all Delivery Years for which such seller offers such resource under the exceptions provided in this subsection (c).

(iii) A Capacity Market Seller offering and clearing a Prior CIL Exception External Resource pursuant to this subsection (c) shall be relieved of its must-offer obligation that would otherwise arise solely from clearing such capacity. Such relief of the must-offer obligation shall be for any Delivery Year after the last Delivery Year for which it is permitted to offer such resource under this subsection (c).

(iv) PJM will determine key triggers for when a Prior CIL Exception External Resource will not be Operationally Deliverable, including the need for: (1) a remedial action scheme or manual generation dump protocol to manage external transmission emergencies; (2) transmission facility switching arrangements that would have the effect of radializing load in order to manage external transmission emergencies; and (3) "out of market" external Balancing Authority or Transmission Operator directed dispatch instructions to manage excessive or unacceptable frequency of external regional reliability limit violations or (outside an interregional agreed congestion management process) of local reliability limit violations.

(d) Seasonal Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, a Seasonal Capacity Performance Resource shall mean a Summer-Period Capacity Performance Resource or Winter-Period Capacity Performance Resource, as defined below.

i) Summer-Period Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, the following types of Capacity Resources are eligible to submit a Sell Offer as a Summer-Period Capacity Performance Resource: Summer Period Demand Resource, Summer-Period Energy Efficiency Resource, and Capacity Storage Resource, Intermittent Resource, or Environmentally-Limited Resource that has an average expected energy output during summer peak-hour periods consistently and measurably greater than its average expected energy output during winter peakhour periods. To the extent such resource clears an RPM Auction or is otherwise committed as a Summer-Period Capacity Performance Resource, it is obligated to deliver energy as scheduled and/or dispatched by the Office of Interconnection during Performance Assessment Intervals occurring in the calendar months of June through October and the following May of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. As further detailed in Tariff, Attachment DD, section 10A, Summer-Period Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d).

ii) Winter-Period Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, the following types of Capacity Resources are eligible to submit a Sell Offer as a Winter-Period Capacity Performance Resource: Capacity Storage Resource, Intermittent Resource, and Environmentally-Limited Resource that has an average expected energy output during winter peak-hour periods consistently and measurably greater than its average expected energy output during summer peak-hour periods. To the extent such resource clears an RPM Auction or is otherwise committed as a Winter-Period Capacity Performance Resource, it is obligated to deliver energy as scheduled and/or dispatched by the Office of Interconnection during Performance Assessment Intervals occurring in the calendar months of November through April of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. As further detailed in Tariff, Attachment DD, section 10A, Winter-Period Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d).

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered through the 2024/2025 Delivery Year.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered.

i) The Office of the Interconnection shall convert Nominated Energy Efficiency Value to an Unforced Capacity basis by multiplying such value by the Forecast Pool Requirement.

ii) The Office of the Interconnection shall convert the nominated Demand Resource value to a UCAP basis by multiplying such value by, the Forecast Pool Requirement through the

2024/2025 Delivery Year, and starting with the 2025/2026 Delivery Year and for subsequent Delivery Years, the applicable ELCC Class Rating.

iii) Demand Resources and Energy Efficiency Resources shall specify the LDA in which the resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on RAA, Schedule 10.1.

e) Accredited UCAP Factor for Generation Capacity Resources beginning with the 2025/2026 Delivery Year and subsequent Delivery Years.

i) The Accredited UCAP Factor shall be the value established by the Office of the Interconnection in accordance with RAA, Schedule 9.2, prior to the applicable RPM Auction. Such Accredited UCAP Factor shall be multiplied by the ICAP offered to convert the ICAP offered into the UCAP offered.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Accredited UCAP Factor determined by the Office of the Interconnection shall apply to such commitment.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

(g) A Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods, not to exceed the Accredited UCAP of such resource, as applicable. Alternatively, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its Capacity Exchange tools. If any of the commercially aggregated resources in such Sell Offer are subject to the Minimum Floor Offer Price pursuant to Tariff, Attachment DD, section 5.14(h-2), the Capacity Market Seller that owns or controls such resources may submit a Sell Offer with a Minimum Floor Offer Price of no lower than the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer.

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Tariff, Attachment Q, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Tariff, Attachment DD, section 6.6, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. An external sale of capacity shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Tariff, Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Tariff, Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Tariff, Attachment DD, section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

5.7 Buy Bids

Buy Bids may be submitted in any Incremental Auction. Buy Bids shall specify, as appropriate:

a) The quantity of Unforced Capacity desired, in increments of 0.1 megawatt;

b) The maximum price, in dollars and cents per megawatt per day, that will be paid by the buyer for the megawatt quantity of Unforced Capacity desired;

c) The type of Unforced Capacity desired, i.e., Annual Resource, and

d) The desired LDA for a replacement Capacity Resource. In the event of delay or cancellation of a Qualifying Transmission Upgrade, the Buy Bid shall specify Capacity Resources in the LDA for which such Qualifying Transmission Upgrade was to increase CETL.

5.8 Submission of Sell Offers and Buy Bids

The Office of the Interconnection shall evaluate and accept or reject Sell Offers and Buy Bids submitted by Capacity Market Sellers on the basis of the following requirements and criteria:

a) A Sell Offer or Buy Bid that fails to specify a positive megawatt quantity shall be rejected by the Office of the Interconnection.

b) A Buy Bid that fails to specify price shall be rejected by the Office of the Interconnection. A Sell Offer that fails to either designate such offer as self-scheduled or to specify an offer price shall be rejected by the Office of the Interconnection.

c) A Buy Bid that fails to designate the type of Unforced Capacity desired, i.e., an Annual Resource, shall be rejected by the Office of the Interconnection.

d) All Sell Offers and Buy Bids must be received by the Office of the Interconnection during a specified period, as determined by the Office of the Interconnection, in accordance with the PJM Manuals. A Sell Offer or Buy Bid may be withdrawn by a notification of withdrawal received by the Office of the Interconnection at any time during the foregoing period, but may not be withdrawn after such period.

e) Sell Offers or Buy Bids shall be submitted or withdrawn via the Internet site designated by the Office of the Interconnection; provided, however, that if the Internet site cannot be accessed at any time during the period specified for the applicable auction, a Sell Offer or Buy Bid may be submitted or withdrawn by electronic mail transmitted to the e-mail address, or faxed to the fax number specified by the Office of the Interconnection.

f) Sell Offers must be based on the Capacity Market Seller's Capacity Resource position at the opening of the auction's bidding window.

g) The Office of the Interconnection shall accept a Sell Offer only up to the megawatt amount of installed capacity of Capacity Resources owned or controlled by such Capacity Market Seller that has not previously been committed for the applicable Delivery Year.

h) No Sell Offer shall be accepted from an FRR Entity unless it meets the requirements applicable to such offers under RAA, Schedule 8.1.

i) The Office of the Interconnection shall have final authority to determine whether to accept or reject a Sell Offer in accordance with the terms of the Tariff and the PJM Manuals.

j) A Capacity Market Seller and Capacity Market Buyer may submit any Sell Offer or Buy Bid, respectively, that it chooses or make a decision not to offer a committed resource, provided that the Office of the Interconnection determines that: (i) the Capacity Market Seller has participated in the review process conducted by the Market Monitoring Unit (without regard to whether an agreement is obtained) if required by the Tariff; (ii) the Sell Offer is no higher, in the case of seller market power, or lower, in the case of buyer side market power, than the level to which the Capacity Market Seller has committed or agreed in the course of its participation in such review process; and (iii) the Sell Offer or Buy Bid is compliant with the Tariff and PJM Manuals. Capacity Market Sellers and Capacity Market Buyers assume exclusive responsibility for their Sell Offers and Buy Bids, respectively, and any adverse findings at the Commission related to its Sell Offers and Buy Bids.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, (through the 2024/2025 Delivery Year), the pool-wide average Accredited UCAP Factor (beginning with the 2025/2026 Delivery Year), the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in Tariff, Attachment DD, section 5.11A;

vii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

viii) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results for each Base Residual Auction shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price.

If PJM discovers a potential error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, along with a description detailing the cause and scope of the error, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. The provided description will not contain information that is market sensitive or confidential. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd) through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with Tariff, Attachment DD, section 5.12(a) and section 5.14(a) above.

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b) above; or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in Tariff, Attachment DD, section 5.12(a), and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) above that is entitled to compensation pursuant to section 5.14(b) above; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) above shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with section 5.14(b) above. Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in section 5.14(a) above.

6. The failure to submit a Sell Offer consistent with section 5.14(c)(i)-(iii) above in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) above in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Tariff, Attachment DD, section 5.10(a)(ii).

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to

establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under Tariff, Attachment DD, section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in Tariff, Attachment DD, section 5.14B, Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D, Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction, First Incremental, or Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) [Reserved for future use]
h-1) [Reserved for future use]
h-2) Minimum Offer Price Rule Effective with the 2023/2024 Delivery Year

(1) **Certification Requirement.**

(A) By no later than one hundred and fifty (150) days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify to the Office of Interconnection for each Generation Capacity Resource the Capacity Market Seller intends to offer into the RPM Auction, in accordance with the PJM Manuals:

(i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification; and

(ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

(B) All Capacity Market Sellers shall be responsible for the accuracy of each certification and its conformance with the Tariff irrespective of any guidance developed by the Office of the Interconnection and the Market Monitoring Unit.

(C) Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the certification requirements in subsection (A)(i) above do not apply and the status of such Generation Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller of the underlying resource) that owns or controls such Generation Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers shall have an ongoing obligation to certify to the Office of Interconnection and the Market Monitoring Unit a Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change. Nothing in this provision shall supersede the requirement for all Capacity Market Sellers to certify to the Office of Interconnection pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii).

(2) **Determining Generation Capacity Resources Subject to the Minimum Offer Price Rule.**

(A) Conditioned State Support.

(i) If the Office of the Interconnection reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource, the Office of Interconnection shall submit, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d, a filing at FERC indicating the Office of the Interconnection's intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource reasonably expected to receive such Conditioned State Support. If FERC has already ruled on whether a specific government program or policy constitutes Conditioned State Support and such policy or program is listed in Tariff, Attachment DD-3, the Office of the Interconnection shall not be required to submit the filing described in the preceding sentence.

(ii) Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to: policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., Cross-State Air Pollution Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

(iii) Upon FERC acceptance (whether by order or operation of law) that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i) that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, will be subject to the provisions of the Minimum Offer Price Rule.

(B) Exercise of Buyer-Side Market Power

(i) If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource, then the underlying Capacity Resource shall be subject to the MOPR pursuant to Tariff, Attachment DD, section 5.14(h-2)(1)(A)(i). If the Office of the Interconnection and/or the Market Monitoring Unit reasonably suspects that a certification submitted under Tariff, Attachment DD, section 5.14(h-2)(1)(A)(ii) contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. During such fact-specific review, the Capacity Market Seller will have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource would not be an Exercise of Buyer-Side Market Power. The Office of the Interconnection and/or the Market Monitoring Unit shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year.

In initiating a review, the Office of the Interconnection and/or the Market Monitoring Unit shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. The Office of the Interconnection and/or the Market Monitoring Unit may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, the Office of the Interconnection and the Market Monitoring Unit shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by the Office of the Interconnection and/or the Market Monitoring Unit, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the Office of the Interconnection, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource that could be an Exercise of Buyer-Side Market Power, as follows:

(a) To determine whether a Capacity Market Seller may have Buyer Side Market Power associated with the Generation Capacity Resource for the applicable RPM Auction, the Office of the Interconnection and/or the Market Monitoring Unit will perform ex-ante testing to determine the extent to which a shift in the supply curve by a number of megawatts equal to the size of the Generation Capacity Resource would affect RPM Auction clearing prices, where such analysis would reflect expected supply and demand conditions in the region of the market clearing prices and quantities in recent RPM Auctions, would reflect whether the relevant LDAs have been constrained in recent RPM Auctions, and would reflect reasonably expected material changes in an LDA including the modeling of the LDA and expected changes in supply and demand for the applicable Delivery Year. To the extent the foregoing analyses show that the Generation Capacity Resource would have a material effect on RPM Auction clearing prices, the Capacity Market Seller shall be deemed to have the ability to exercise Buyer Side Market Power.

(b) To determine whether the Capacity Market Seller's submission of a Sell Offer at any given price level for such Generation Capacity Resource may constitute an Exercise of Buyer-Side Market Power, the Office of the Interconnection and/or the Market Monitoring Unit shall perform ex-ante testing to determine whether, given the ability to suppress prices identified in the relevant LDAs and the PJM Region, such price suppression would be economically beneficial to the Capacity Market Seller by comparing its expected cost with its economic benefit, and where the expected cost shall reflect the excess economic costs of the resource above expected market revenues, and the expected benefit shall reflect the expected cost savings to the expected net short position (based on estimated capacity obligations and owned and contracted capacity measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction in which the Generation Capacity Resource is being offered) in the relevant LDAs and RTO multiplied by the price change resulting from offering the resource uneconomically. In this analysis, the Office of Interconnection and/or the Market Monitoring Unit shall consider whether any capacity obligations in which the capacity costs based on RPM Auction clearing prices are directly passed through to load and consider whether the price of any contracted capacity passes through RPM Auction clearing prices. If the expected benefit outweighs the expected cost, the Capacity Market Seller shall be deemed to have the incentive to exercise Buyer Side Market Power. If a resource offer can be justified, economically or otherwise, without consideration of the benefit to the Capacity Market Seller of the suppressed prices, the Capacity Market Seller shall be deemed not to have the incentive to exercise Buyer Side Market Power with respect to that resource. Out-of-market compensation (such as from renewable energy credits and zero emission credits) that are not tied to either Conditioned State Support or a bilateral contract that directs the submission of an offer to lower market clearing prices may be used to support the economics of the resource under review.

(ii) The following nonexhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review initiated pursuant to subsection (i) above: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller's long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power.

(iii) Based on the foregoing tests and fact-specific review, including the facts and circumstances of the Generation Capacity Resource, the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If the Office of the Interconnection, with the advice and input of the Market Monitoring Unit, determines that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, the Office of the Interconnection shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the Office of the Interconnection's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on its determination hereunder unless FERC by order directs otherwise.

(C) Failure to timely submit a certification. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications required under Tariff, Attachment DD, section 5.14(h-2)(1) shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception pursuant to Tariff, Attachment DD, section 5.14(h-2)(4) for the relevant Delivery Year, and PJM approves the unit-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

(3) **Minimum Offer Price Rule.** Any Sell Offer for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) shall have an offer price no lower than the applicable MOPR Floor Offer Price, unless the applicable MOPR Floor Offer Price is higher than the applicable Market Seller Offer Cap, in which circumstance the Capacity Market Seller, to participate in an RPM Auction, must request a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process, and the unit-specific MOPR Floor Offer Price shall establish the offer level for such resource.

(A) New Entry MOPR Floor Offer Price. For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource, or any uprate of such Generation Capacity Resource participating in the generation interconnection process under Tariff, Part IV, Subpart A, that has not cleared an RPM Auction for any Delivery Year, the applicable MOPR Floor Offer Price, based on the net cost of new entry for the resource type, shall be, at the election of the Capacity Market Seller, (i) the unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process in Tariff, Attachment DD, section 5.14(h-2)(4) below or (ii) if applicable, the default New Entry MOPR Floor Offer Price for the applicable resource based on the gross cost of new entry values shown in the table below, as adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, net of estimated net energy and ancillary service revenues for the resource type and Zone in which the resource is located.

Resource Type	**Through the 2025/2026 Delivery Years: Gross Cost of New Entry (2022/2023 $/ MW-day) (Nameplate)**	**For the 2026/2027 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2026/2027 $/ MW-day) (Nameplate)**
Nuclear	$2,000	$2,568
Coal	$1,068	$1,480
Combined Cycle	$320	$540
Combustion Turbine	$294	$427
Fixed Solar PV	$271	$298
Tracking Solar PV	$290	$321
Onshore Wind	$420	$438
Offshore Wind	$1,155	$1,351
Battery Energy Storage	$532	$502

The gross cost of new entry values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. For purposes of submitting a Sell Offer, the gross cost of new entry values must be converted to a net cost of new entry by subtracting the estimated net energy and ancillary service revenues, as determined below, from the gross cost of new entry. However, the resultant net cost of new entry of the battery energy storage resource type in the table above must be multiplied by 2.5. The net cost of new entry based on nameplate capacity is then converted to Unforced Capacity ("UCAP") MW-day. For the 2023/2024 and 2024/2025 Delivery Years, the net cost of new entry is adjusted using: for battery storage, wind, and solar resource types, the applicable ELCC Class Rating; or for all other generation resource types, the applicable class average EFORd. For the 2025/2026 Delivery Year and subsequent Delivery Years, the net cost of new entry is adjusted by the applicable class average Accredited UCAP Factor. The resulting default New Entry MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default gross costs of new entry in the table above and post the preliminary estimates of the adjusted applicable default New Entry MOPR Floor Offer Prices on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted applicable default New Entry MOPR Floor Offer Prices for all resource types, the Office of the Interconnection shall adjust the gross costs of new entry utilizing, for combustion turbine and combined cycle resource types, the same Applicable BLS Composite Index applied for such Delivery Year to adjust the CONE value used to determine the Variable Resource Requirement Curve, in accordance with Tariff, Attachment DD, section 5.10(a)(iv), and for all other resource types, the "BLS Producer Price Index Turbines and Turbine Generator Sets" component of the Applicable BLS Composite Index used to determine the Variable Resource Requirement Curve shall be replaced with the "BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment" when adjusting the gross costs of new entry. The resultant value shall then be then adjusted further by a factor of 1.022 for nuclear, coal, combustion turbine, and combine cycle resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. Updated estimates of the net energy and ancillary service revenues for each default resource type and applicable Zone, which shall include, but are not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2 shall then be subtracted from the adjusted gross costs of new entry to determine the adjusted New Entry MOPR Floor Offer Price. The net energy and ancillary services revenue is equal to the average of the annual net revenues of the three most recent calendar years preceding the Base Residual Auction, where such annual net revenues shall be determined in accordance with the following and the PJM Manuals:

(i) for nuclear resource type, the net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [average annual zonal day-ahead LMP, times 8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of Maintenance Adder costs, plus an ancillary services revenue of $3,350/MW-year;

(ii) for coal resource type, the net energy and ancillary services revenue estimate shall be determined by a simulated dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance variable operation and maintenance expenses, inclusive of Maintenance Adder costs, of $9.50/MWh) using applicable coal prices, as set forth in the PJM Manuals, plus reactive services revenue of $3,350/MW-year. The unit is committed day-ahead in profitable blocks of at least eight hours, and then committed in real-time for profitable hours if not already committed day ahead;

(iii) for combustion turbine resource type, the net energy and ancillary services revenue estimate shall be determined in a manner consistent with the methodology described in Tariff, Attachment DD, section 5.10(a)(v)(B) for the Reference Resource combustion turbine.

(iv) for combined cycle resource type, the net energy and ancillary services revenue estimate shall be determined in the same manner as that prescribed for a combustion turbine resource type, except that the heat rate assumed for the combined cycle resource shall be 6,553 BTU/kwh, the variable operations and maintenance expenses for such resource, inclusive of Maintenance Adder costs, shall be $2.11/MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in Peak-Hour Dispatch, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary services revenue shall be $3,350/MW-year.

(v) for solar PV resource type, the net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource;

(vi) for onshore wind resource type, the net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the real-time zonal LMP applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year;

(vii) for offshore wind resource type, the net energy and ancillary services revenue estimate shall be the product of [the average annual zonal real-time LMP times 8,760 hours times an assumed annual capacity factor of 45%], plus an ancillary services revenue of $3,350/MW-year; and

(viii) for Capacity Storage Resource, the net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch against historical real-time zonal LMPs where the resource is assumed to be dispatched for the four hours of highest LMP of a daily twenty-four hour period if the average LMP of these four hours exceeds 120% of the average LMP of the four lowest LMP hours of the same twenty-four hour period. The net energy market revenues will be determined by the product of [hourly output of 1 MW times the hourly LMP for each hour of assumed discharging] minus the product of [hourly consumption of 1.2 MW times the hourly LMP for each hour of assumed charging] with this net value summed across all of the hours of an annual period, plus an ancillary services revenue of $3,350/MW-year. An 83.3% efficiency of the battery energy storage resource is reflected by assuming each 1.0 MW of discharge requires 1.2 MW of charge.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default gross cost of new entry values. Such review may include, without limitation, analyses of the fixed development, construction, operation, and maintenance costs for such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default gross cost of new entry values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default gross cost of new entry values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has not previously cleared an RPM Auction for that or any prior Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource for the relevant RPM Auction.

(B) Cleared MOPR Floor Offer Prices.

For a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price shall be, at the election of the Capacity Market Seller, (a) based on the unit-specific MOPR Floor Offer Price, as determined in accordance with Tariff, Attachment DD, section 5.14(h-2)(4) below, or (b) if available, the default Avoidable Cost Rate for the applicable resource type shown in the table below, as adjusted for Delivery Years subsequent for the 2022/2023 or 2026/2027 Delivery Year, as applicable, to reflect changes in avoidable costs, net of projected PJM market revenues equal to the resource's historical net energy and ancillary service revenues consistent with Tariff, Attachment DD, section 6.8(d).

Existing Resource Type	Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023) ($/MW-day) (Nameplate)	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) ($/ MW-day) Nameplate
Nuclear - single	$697	$591
Nuclear - dual	$445	$537
Coal	$80	$94
Combined Cycle	$56	$113
Combustion Turbine	$50	$52
Steam Oil & Gas	NA	$64
Solar PV (fixed and tracking)	$40	$70
Wind Onshore	$83	$147

The default gross Avoidable Cost Rate values in the table above are expressed in dollars per MW-day in terms of nameplate megawatts. Through the 2024/2025 Delivery Year, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, where the UCAP MW-day value will be determined based on the resource-specific Accredited UCAP value for solar and wind resource types (with appropriate time-weighting for any winter Capacity Interconnection Rights) or the resource-specific EFORd for all other generation resource types. Effective for the 2025/2026 Delivery Year and subsequent Delivery Years, for purposes of submitting a Sell Offer, the default Avoidable Cost Rate values must be net of estimated net energy and ancillary service revenues, and then the difference is ultimately converted to Unforced Capacity ("UCAP") MW-day, based on the resource's Accredited UCAP Factor. The resulting default Cleared MOPR Floor Offer price in UCAP/MW-day terms shall be applied to each MW offered for the Capacity Resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.

Commencing with the Base Residual Auction for the 2023/2024 Delivery Year, the Office of the Interconnection shall adjust the default Avoidable Cost Rates in the table above, and post the adjusted values on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the adjusted Avoidable Cost Rates, the Office of the Interconnection shall utilize the 10-year average Handy-Whitman Index in order to adjust the Gross ACR values to account for expected inflation. Updated estimates of the net energy and ancillary service revenues shall be determined on a resource-specific basis in accordance with Tariff, Attachment DD, section 6.8(d) and the PJM Manuals.

Beginning with the Delivery Year that commences June 1, 2022, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the default Avoidable Cost Rates for Capacity Resource that is subject to the provisions of the Minimum

Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) that have cleared in an RPM Auction for any Delivery Year. Such review may include, without limitation, analyses of the avoidable costs of such resource types. Based on the results of such review, PJM shall propose either to modify or retain the default Avoidable Cost Rate values stated in the table above. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the default Avoidable Cost Rate values are proposed, the Office of the Interconnection shall file such proposed modifications with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Any Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction for any Delivery Year and for which there is no default MOPR Floor Offer Price provided in accordance with this section, including hybrid resources, must seek a unit-specific value determined in accordance with the unit-specific MOPR Floor Offer Price process below to participate in an RPM Auction. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer based on such resource.

(4) **Unit-Specific Exception**. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Capacity Resource. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction for a Generation Capacity Resource that is under a fact-specific review for Buyer-Side Market Power pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B)(ii), and where the offer is below the applicable default MOPR Floor Offer Price may, at its election, submit a request for a unit-specific exception for such Generation Capacity Resource. A Sell Offer below the default MOPR Floor Offer Price, but no lower than the unit-specific MOPR Floor Offer Price, shall be permitted if the Capacity Market Seller obtains approval from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer. The unit-specific MOPR Floor Offer Price determined under this provision shall be based on the unit-specific Accredited UCAP value for battery energy storage resource types and for solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights) or on the unit-specific EFORd for all other generation resource types, and shall be applied to each MW offered by the resource regardless of actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource. Such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of the resource. All supporting data must be provided for all requests. The following requirements shall apply to requests for such determinations:

(A) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, the Capacity Market Seller shall submit the unit-specific exception request to the Office of the Interconnection and the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM

Auction, a preliminary estimate for the relevant Delivery Year of the default Minimum Floor Offer Prices, determined pursuant to Tariff, Attachment DD, sections 5.14(h-2)(3)(A) and (B). If the final applicable default Minimum Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(B) For a unit-specific exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has never cleared an RPM Auction, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of offsetting net revenues.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits or any other revenues outside of PJM markets that do not constitute Conditioned State Support), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (e.g., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

Supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. In addition to the certification, signed by an officer of the Capacity Market Seller, the request must include a certification that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a unit-specific exception hereunder. The request also shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside the PJM market not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, which may include Maintenance Adders, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

(C) For a Unit-Specific Exception for a Generation Capacity Resource that is subject to the provisions of the Minimum Offer Price Rule pursuant to Tariff, Attachment DD, section 5.14(h-2)(2) and that has previously cleared an RPM Auction, the Capacity Market Seller shall submit a Sell Offer consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request for an exception under this subsection documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, evidence of compensation outside of PJM markets not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, which may include Maintenance Adders, and emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

(D) A Sell Offer evaluated at the unit-specific exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the default MOPR Floor Offer Price, based on competitive cost advantages relative to the costs estimated by the default MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those estimated by the default MOPR Floor Offer Price. Capacity Market Sellers shall demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection, and that out-of-market compensation is not tied to Conditioned State Support or a bilateral contract that directs submission of an offer to lower RPM Auction clearing prices. Failure to adequately support such claimed cost advantages or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in the elimination of consideration of the unsupported element(s) of a unit-specific exception by the Office of the Interconnection.

(E) The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the unit-specific exception request and that to the best of his/her knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

(F) The Market Monitoring Unit shall review, in an open and transparent manner with the Capacity Market Seller and the Office of the Interconnection, the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review, in an open and transparent manner, all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. After the Office of the Interconnection determines with the advice and input of Market Monitor, the acceptable minimum Sell Offer, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction, and in making such determination, the Capacity Market Seller may consider the applicable default MOPR Floor Offer Price and may select such default value if it is lower than the unit-specific determination. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules based on the lower of the applicable default MOPR Floor Offer Price and the unit-specific determination unless and until ordered to do otherwise by FERC.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) above also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under Tariff, Attachment DD, section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) above times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource above $0/MW-day, except as described in Tariff, Attachment DD, section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the applicable default level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource as outlined in Tariff, Attachment M-Appendix, section II.G. Any Sell Offer submitted in any auction that is inconsistent with any agreement or commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required to resubmit a Sell Offer that complies with such agreement or commitment within one (1) Business Day of the Office of the Interconnection's rejection of such

Sell Offer. If the Capacity Market Seller does not timely resubmit its Sell Offer, fails to request a unit-specific Avoidable Cost Rate by the specified deadline, or if the Office of the Interconnection determines that the information provided by the Capacity Market Seller in support of the requested unit-specific Avoidable Cost Rate or Sell Offer is incomplete, the Capacity Market Seller shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default offer for the applicable class of resource or nearest comparable class of resource determined under this subsection (c)(ii). The obligation imposed under section 6.6(a) above shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 above and Tariff, Attachment M-Appendix, section II.H.

The default retirement and mothball Avoidable Cost Rates ("ACR") referenced in this subsection (c)(ii) are as set forth in the tables below for the 2013/2014 Delivery Year through the 2016/2017 Delivery Year. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e) below, in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates. A Capacity Market Seller may not use the default Market Seller Offer Cap contained in the ACR tables in this subsection, and also seek to include any one or more categories of the Avoidable Cost Rate defined section 6.8 below.

Maximum Avoidable Cost Rates by Technology Class								
Technology	**2013/14 Mothball ACR ($/MW-Day)**	**2013/14 Retirement ACR ($/MW-Day)**	**2014/15 Mothball ACR ($/MW-Day)**	**2014/15 Retirement ACR ($/MW-Day)**	**2015/16 Mothball ACR ($/MW-Day)**	**2015/16 Retirement ACR ($/MW-Day)**	**2016/2017 Mothball ACR ($/MW-Day)**	**2016/2017 Retirement ACR ($/MW-Day)**
Nuclear	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pumped Storage	$23.64	$33.19	$24.56	$34.48	$25.56	$35.89	$24.05	$33.78
Hydro	$80.80	$105.67	$83.93	$109.76	$87.35	$114.24	$82.23	$107.55
Sub-Critical Coal	$193.98	$215.02	$201.49	$223.35	$209.71	$232.46	$197.43	$218.84
Super Critical Coal	$200.41	$219.21	$208.17	$227.70	$216.66	$236.99	$203.96	$223.10
Waste Coal - Small	$255.81	$309.83	$265.72	$321.83	$276.56	$334.96	$260.35	$315.34
Waste Coal – Large	$94.61	$114.29	$98.27	$118.72	$102.28	$123.56	$96.29	$116.32
Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CC-2 on 1 Frame F	$35.18	$49.90	$36.54	$51.83	$38.03	$53.94	$35.81	$50.79
CC-3 on 1 Frame E/Siemens	$39.06	$52.89	$40.57	$54.94	$42.23	$57.18	$39.75	$53.83
CC–3 or More on 1 or More Frame F	$30.46	$42.28	$31.64	$43.92	$32.93	$45.71	$30.99	$43.03
CC-NUG Cogen. Frame B or E Technology	$130.76	$175.71	$135.82	$182.52	$141.36	$189.97	$133.09	$178.83
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$27.96	$37.19	$29.04	$38.63	$30.22	$40.21	$28.45	$37.85
CT - 1st & Gen. Frame B	$27.63	$36.87	$28.70	$38.30	$29.87	$39.86	$28.11	$37.52
CT - 2nd Gen. Frame E	$26.26	$35.14	$27.28	$36.50	$28.39	$37.99	$26.73	$35.77
CT - 3rd Gen. Aero (GE LM 6000)	$63.57	$93.70	$66.03	$97.33	$68.72	$101.30	$64.70	$95.37
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$33.34	$49.16	$34.63	$51.06	$36.04	$53.14	$33.93	$50.03
CT - 3rd Gen. Frame F	$26.96	$38.83	$28.00	$40.33	$29.14	$41.98	$27.43	$39.52
Diesel	$29.92	$37.98	$31.08	$39.45	$32.35	$41.06	$30.44	$38.66

Oil and Gas Steam	$74.20	$90.33	$77.07	$93.83	$80.21	$97.66	$75.51	$91.94

Commencing with the Base Residual Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall determine the default retirement and mothball Avoidable Cost Rates referenced in section (c)(ii) above, and post them on its website, by no later than one hundred fifty (150) days prior to the commencement of the offer period for each Base Residual Auction. To determine the applicable ACR rates, the Office of the Interconnection shall use the actual rate of change in the historical values from the Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission ("Handy-Whitman Index") to the extent they are available to update the base values for the Delivery Year, and for future Delivery Years for which the updated Handy-Whitman Index values are not yet available the Office of the Interconnection shall update the base values for the Delivery Year using the most recent ten-calendar-year annual average rate of change. The ACR rates shall be expressed in dollar values for the applicable Delivery Year.

Maximum Avoidable Cost Rates by Technology Class (Expressed in 2011 Dollars for the 2011/2012 Delivery Year)		
Technology	**Mothball ACR ($/MW-Day)**	**Retirement ACR ($/MW-Day)**
Combustion Turbine - Industrial Frame	$24.13	$33.04
Coal Fired	$136.91	$157.83
Combined Cycle	$29.58	$40.69
Combustion Turbine - Aero Derivative	$26.13	$37.18
Diesel	$25.46	$32.33
Hydro	$68.78	$89.96
Oil and Gas Steam	$63.16	$76.90
Pumped Storage	$20.12	$28.26

To determine the default retirement and mothball ACR values for the 2017/2018 Delivery Year, the Office of the Interconnection shall multiply the base default retirement and mothball ACR values in the table above by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Indices for the 2011 to 2013 calendar years to determine updated base default retirement and mothball ACR values. The updated base default retirement and mothball ACR values shall then be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.

PJM shall also publish on its website the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

After the Market Monitoring Unit conducts its annual review of the table of default Avoidable Cost Rates included in section 6.7(c) above in accordance with the procedure specified in Tariff, Attachment M-Appendix, section II.H, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection determines that the values should be updated, the Office of the Interconnection shall file its proposed values with the Commission by no later than October 30th prior to the commencement of the offer period for the first RPM Auction for which it proposes to apply the updated values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection relevant unit-specific cost data concerning each data item specified as set forth in section 6 by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. If cost data is not available at the time of submission for the time periods specified in section 6.8 below, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used, as may be further specified in the PJM Manuals. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination pursuant to Tariff, Attachment M-Appendix, section II.E.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in section 6.4 above). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues: Projected PJM Market Revenues are defined by section 6.8(d) below, for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction, a Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR + CPQR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

    - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

    - **AFAE (Avoidable Fuel Availability Expenses) c**onsists of avoidable operating expenses related directly to fuel availability and delivery for the generating unit that can be demonstrated by the Capacity Market Seller based on data for the twelve months preceding the month in which the data must be provided , or on reasonable projections for the Delivery Year supported by executed contracts, published tariffs, or other data sufficient to demonstrate with reasonable certainty the level of costs that have been or shall be incurred for such purpose. The categories of expenses included in AFAE are those incurred for: (a) firm gas pipeline transportation; (b) natural gas storage costs; (c) costs of gas balancing agreements; and (d) costs of gas park and loan services. AFAE expenses are for firm fuel supply and apply solely for offers for a Capacity Performance Resource

- **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

- **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

- **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of non-performance associated with submission of a Capacity Performance Resource offer, such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

- **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor, applied in accordance with the terms specified below. CRF values are calculated for recovery periods of 4, 5, 10, 15, 20, 25, and 30 years, using the following formula with assumptions of the following components: (i) capital structure and cost of capital; (ii) debt interest rate; (iii) state income tax rate, and (iv) federal income tax and depreciation rates as utilized by the U.S. Internal Revenue Service.

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{m_j}{(1+r)^j}\right]}{(1-s)\sqrt{1+r}\,[(1+r)^N - 1]}$$

Where:

r is the after tax Weighted Average Cost of Capital (calculated as: percent equity * cost of equity + percent debt * debt interest rate * (1- effective tax rate))
s is the effective tax rate (calculated as: State Tax Rate + Federal Tax Rate*(1-State Tax Rate))
B is the bonus depreciation percent
N is the cost recovery period (years)
L is the lessor of N or 16 (years)
m_j is the modified accelerated cost recovery system (MACRS) depreciation factor for year j =1, . . ., 16.

The CRF values of the following table shall be used for RPM Auctions through and including the Base Residual Auction conducted for 2022/2023 Delivery Year. Thereafter, the table of CRF values applicable to each RPM Auction shall be determined and posted on the PJM website by no later than 150 days prior to the commencement of the offer period of the RPM Auction. The values of the posted CRF table shall be determined using federal income tax laws in effect at the time of the determination for the relevant Delivery Year and shall use the same assumptions of (i) capital structure and cost of capital; (ii) debt interest rate; and (iii) state income tax rate, as those utilized to calculate the Cost of New Entry for the Reference Resource for the relevant Delivery Year. For the purpose of the CRF determination, the state income tax rate will be set equal to the average state income tax rate used to calculate the Cost of New Entry of the Reference Resource across the four CONE Regions. The CRF for the 40 Plus Alternative option shall be set equal to 1.1 and is not calculated by the formula above.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

<u>Capital Expenditures and Project Investment</u>

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above or posted table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above or posted table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the

Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Tariff, Part V. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under Tariff, Attachment DD, section 5.14(c).

- **ARPIR (Avoidable Refunds of Project Investment Reimbursements)** consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Tariff, Part V, section 118 or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Tariff, Part V, section 119 and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) Variable costs that are directly attributable to the production of energy shall be excluded from a Market Seller's generation resource Avoidable Cost Rate.

(d) For Delivery Years up to and including the 2021/2022 Delivery Year and for the 2023/2024 Delivery Year and subsequent Delivery Years, projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. Net energy market revenues shall be based on the non-zero market-based offers of the Capacity Market Seller of such Generation Capacity Resource unless one of the following conditions is met, in which case the cost-based offer shall be used: (x) the market-based offer for the resource is zero, (y) the market-based offer for the resource is higher than its cost-based offer and such offer has been mitigated, or (z) the market-based offer for the resource is less than such Capacity Market Seller's fuel and environmental costs for the resource which shall be determined either by directly summing the fuel and environmental costs if they are available, or by subtracting from the cost-based offer for the resource all costs developed pursuant to the Operating Agreement and PJM Manuals that are not fuel or environmental costs.

The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

(d-1) For the 2022/2023 Delivery Year, Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall be equal to forecasted net revenues, which shall be determined in accordance with Tariff, Attachment DD, section 5.14(h-1)(2)(B)(ii), or for resource types not specified in such section, in a manner consistent with the methodologies described in such section, that utilizes Forward Hourly LMPs and Forward Hourly Ancillary Service Prices for such resource, forecasted fuel prices as applicable, as well as resource-specific operating parameters and capability information specific to the simulated dispatch of such resource, where such dispatch shall either consider the hourly output profiles for Intermittent Resources in a manner consistent with solar and onshore wind methodologies, or utilize the Projected EAS Dispatch. To the extent the resource has achieved commercial operation, the dispatch shall utilize the resource-specific operating parameters as determined in accordance with the PJM Manuals based on offers submitted in the Day-ahead Energy Market and Real-time Energy Market, as well as the operating parameters approved, as applicable, in accordance with Operating Agreement, Schedule 1, section 6.6(b) and Operating Agreement, Schedule 2 (including any Fuel Costs, emissions costs, Maintenance Adders, and Operating Costs). Adjustments to resource-specific operating parameters may be submitted to the Market Monitoring Unit and the Office of the Interconnection for review and consideration in the simulated dispatch with supporting documentation. For resources that have not yet achieved commercial operation, the operating parameters used in the simulation of the net energy and ancillary service revenues will be based on the manufacturer's specifications and/or from parameters used for other existing, comparable resources, as developed by the Market Monitoring Unit and the Capacity Market Seller, and accepted by the Office of the Interconnection.

In the alternative, the Capacity Market Seller may provide their own estimate of Projected PJM Market Revenues to the Market Monitoring Unit and the Office of the Interconnection for review and approval. Such a request shall identify all revenue sources (exclusive of any State Subsidies), including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standards prescribed above. In making such demonstration, the Capacity Market Seller may rely upon revenues projected by well-defined, forward-looking dispatch models designed to generally follow the rules and processes of PJM's energy and ancillary services markets. Such models must utilize forward prices for energy, ancillary service and fuel in the PJM Region based on contractual evidence of an alternative fuel price or sourced from liquid forward markets (where available), and other publicly available data to develop the forward prices used in the estimate. Where forward fuel markets are not available, publicly available estimates of future fuel sources may be used. The model shall also contain estimates of variable operation and maintenance expenses, which may include Maintenance Adders, and emissions allowance prices. Documentation for net revenues also must include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, capacity factors, and ancillary service capabilities. Any evaluation of revenues should include, but would not be not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable, pursuant to Operating Agreement, Schedule 2.

8. CAPACITY RESOURCE DEFICIENCY CHARGE

8.1

A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resource) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:

a) Unit Derating – Such Capacity Resource is a Generation Capacity Resource and its capacity value is derated prior to or during the Delivery Year;

b) EFORD Increase – Such Capacity Resource is a Generation Capacity Resource and the EFORD value determined for such resource at least two (2) months prior to the Third Incremental Auction is higher than the EFORD value submitted in the Capacity Market Seller's cleared Sell Offer;

c) External Generation Resource – Such Capacity Resource is an Existing Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;

d) Planned Generation Resource – Such Capacity Resource is a Planned Generation Capacity Resource and Interconnection Service has not commenced as to such resource prior to the start of the Delivery Year;

e) Planned Demand Resource - Such Capacity Resource is a Planned Demand Resource or an Energy Efficiency Resource and the associated demand response program or energy efficiency measure is not installed prior to the start of the Delivery Year; or

f) Existing Demand Resource – Such Capacity Resource is an existing Demand Resource or Energy Efficiency Resource and, subject to section 8.4 below, is not capable of providing the megawatt quantity of load response specified in the cleared Sell Offer for the time periods of availability associated with the product type.

8.2. Capacity Resource Deficiency Charge

The Capacity Resource Deficiency Charge shall equal the Daily Deficiency Rate (as defined in Tariff, Attachment DD, section 7) multiplied by the megawatt quantity of deficiency below the level of capacity committed in such Capacity Market Seller's Sell Offer(s) or bilateral capacity commitments, or Locational UCAP Seller's Locational UCAP sale for each day such seller is deficient, provided, however, that a resource that is subject to a charge under this section that is also subject to a charge under Tariff, Attachment DD, section 10A hereof for a Performance Shortfall during one or more Performance Assessment Intervals occurring during the period of resource deficiency addressed by this section shall be assessed a charge equal to the greater of the charge determined under this section and the charge determined under Tariff, Attachment DD, section 10A, but shall not be assessed a charge under both this section and Tariff, Attachment DD, section 10A for such simultaneous occurrence of a resource deficiency and Performance Shortfall.

8.3. Allocation of Revenue Collected from Capacity Resource Deficiency Charges

The revenue collected from the assessment of a Capacity Resource Deficiency Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

8.4 Relief from Charges

A Capacity Market Seller or Locational UCAP Seller that is otherwise subject to the Capacity Resource Deficiency Charge solely as a result of section 8.1(f) above may receive relief from such Charge if it demonstrates that the inability to provide the level of demand response specified in its Sell Offer is due to the permanent departure (due to plant closure, efficiency gains, or similar reasons) from the Transmission System of load that was relied upon for load response in such Sell Offer; provided, however, that such seller must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief. Such seller shall receive no RPM Auction Credit for the amount of reduction in the committed Existing Demand Resources.

10A. CHARGES FOR NON-PERFORMANCE AND CREDITS FOR PERFORMANCE

(a) For the 2018/2019 Delivery Year and any subsequent Delivery Year (and for certain purposes for the 2016/2017 and 2017/2018 Delivery Years as provided in subsections (h) and (i) hereof), each Capacity Market Seller that commits a Capacity Resource for a Delivery Year (whether through an RPM Auction, a bilateral transaction, or as Locational UCAP), each Locational UCAP Seller that sells Locational UCAP from a Capacity Resource for a Delivery Year, and for the 2022/2023 Delivery Year and subsequent Delivery Years each PRD Provider that commits Price Responsive Demand for a Delivery Year, shall be charged to the extent the performance of each of its committed Capacity Resources or Price Responsive Demand during all or any part of a clock-hour when an Emergency Action is in effect falls short of the expected performance of such resources (as determined herein) and the revenue from such charges shall be provided to Market Participants with generation, demand response resources, or Price Responsive Demand that perform during such hour in excess of the level expected based on commitments (if any) of such resources.

(b) Performance shall be measured for purposes of this assessment during each Performance Assessment Interval.

(c) For each Performance Assessment Interval, the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource and Locational UCAP has fallen short of the performance expected of such committed Capacity Resource, and the magnitude of any such shortfall, based on the following formula:

Performance Shortfall = Expected Performance - Actual Performance

Where the result of such formula is a positive number and where:
Expected Performance =

> for Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve a declared Emergency Action; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and Capacity Storage Resources: [(Resource Committed Capacity * the Balancing Ratio)];
>
> > where
> >
> > Resource Committed Capacity = the total megawatts of Unforced Capacity of the Capacity Resource committed by such Capacity Market Seller or Locational UCAP Seller; and
> >
> > The Balancing Ratio = (All Actual Generation Performance, Storage Resource Performance, Net Energy Imports, Price Responsive Demand Bonus Performance effective with the 2022/2023 Delivery Year, and Demand Response Bonus

Performance) / (All Committed Generation and Storage Capacity); provided, however, that Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Interval for which performance by any external Generation Capacity Resource would have helped resolve the Emergency Action that was the subject to the Performance Assessment Hour; and provided further that for any Delivery Year up to and including the 2019/2020 Delivery Year, Net Energy Imports shall be included in the calculation of the Balancing Ratio only for any Performance Assessment Hour for which the Emergency Action was declared for the entire PJM Region; and provided further that the Balancing Ratio shall not exceed a value of 1.0.

for purposes of which

All Committed Generation and Storage Capacity = the total megawatts of Unforced Capacity of all Generation Capacity Resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and all Capacity Storage Resources committed by all Capacity Market Sellers, FRR Entities, Locational UCAP Sellers;

All Actual Generation Performance and Storage Resource Performance = the total amount of Actual Performance for all generation resources (including external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, performance of external Generation Capacity Resources shall be assessed only during Performance Assessment Hours for Emergency Actions declared for the entire PJM Region) and storage resources during the interval;

Net Energy Imports = the sum of interchange transactions importing energy into PJM (not including those associated with external Generation Capacity Resources and therefore included in All Actual Generation Performance) minus the sum of interchange transactions exporting energy out of PJM, but not less than zero;

Demand Response Bonus Performance = the sum of Bonus performance provided by Demand Response resources as calculated in (g) below;

Price Responsive Demand Bonus Performance = the sum of Bonus performance provided by Price Responsive Demand as calculated in (g) below;

and for Demand Resources, Energy Efficiency Resources, and Qualifying Transmission

Upgrades: Resource Committed Capacity;

where

Resource Committed Capacity = the total megawatts of capacity committed from such Capacity Resource committed capacity without making any adjustment for the Forecast Pool Requirement

and for PRD Provider: Price Responsive Demand Committed

where

Price Responsive Demand Committed = the Nominal PRD Value committed by the PRD Provider in the area defined by the Performance Assessment Interval, adjusted to account for any PRD registrations in such area that were not subject to compliance measurement.

and

Actual Performance =

for each generation resource, the metered output of energy delivered to PJM by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each storage resource, the metered output of energy delivered to PJM by such resource plus the resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval;

for each Demand Resource, the demand response provided to PJM by such resource, plus such resource's real-time reserve or regulation assignment, if any, during the Performance Assessment Interval, as established through the PJM demand response settlement procedure consistent with the standards specified in RAA, Schedule 6;

for each PRD Provider, the actual load reduction provided by the PRD Provider during a Performance Assessment Interval, determined in accordance with RAA, Schedule 6.1.N and the PJM Manuals;

for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation measurement and verification report; and

for each Qualified Transmission Upgrade, the megawatt quantity cleared by such Qualified Transmission Upgrade if it is in service during the Performance Assessment Interval, and zero if it is not in service during such Performance

Assessment Interval.

Such calculation shall encompass all resources and Price Responsive Demand located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval.

(d) Notwithstanding subsection (c) above, a Capacity Resource or Locational UCAP of a Capacity Market Seller or Locational UCAP Seller shall not be considered in the calculation of a Performance Shortfall for a Performance Assessment Interval to the extent such Capacity Resource or Locational UCAP was unavailable during such Performance Assessment Interval solely because the resource on which such Capacity Resource or Locational UCAP is based was on a Generator Planned Outage or Generator Maintenance Outage approved by the Office of the Interconnection, or was not scheduled to operate by the Office of the Interconnection, or was online but was scheduled down, by the Office of the Interconnection, based on a determination by the Office of the Interconnection that such scheduling action was appropriate to the security-constrained economic dispatch of the PJM Region. Such a resource shall be considered in the calculation of a Performance Shortfall if it otherwise was needed and would have been scheduled by the Office of the Interconnection to perform, but was not scheduled to operate, or was scheduled down, solely due to: (i) any operating parameter limitations submitted in the resource's offer, or (ii) the seller's submission of a market-based offer higher than its cost-based. In addition, notwithstanding subsection (c) above, a Price Responsive Demand registration shall not be considered in the calculation of a Performance Shortfall or Bonus Performance for a Performance Assessment Interval when the PRD Curve associated with such registration in the PJM Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:

Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate

Where

For Capacity Performance Resources and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour).

(f) The Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource or such PRD Provider times the number of days in the Delivery Year. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.

(f-1) Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource or such PRD Provider, where such megawatts shall be based on the maximum Unforced Capacity committed up through the end of the month in which the PAI occurs, times the number of days in the Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource, where such megawatts shall be based on maximum Unforced Capacity committed up through the end of the month in which the Performance Assessment Interval occurs, times the number of days in the season applicable to such resource.

(g) Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval, that provided energy or load reductions above the levels expected for such resource during such interval. For purposes of this provision, the performance expected of a resource, and the revenue distribution payment, if any, for a resource, shall be determined in accordance with the following formulae:

Formula 1: Market Participant Bonus Performance = Actual Performance – Expected Performance

and

Formula 2: Performance Payment = (Market Participant Bonus Performance / All Market Participants Bonus Performance) * Non-Performance Charge Revenues.

Where the result of Formula 1 is a positive number and where:

Actual Performance is as defined in subsection (c), provided, however, that Actual Performance for purposes of this calculation shall not exceed the megawatt level at which such resource was scheduled by the Office of the Interconnection during the Performance Assessment Intervals; and provided further that Actual Performance for a Market Participant that imports energy into the PJM Region during such Performance Assessment Interval shall be the net import, if any, from all interchange transactions scheduled by such Market Participant during such Performance Assessment Interval;

Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the resource's capacity obligation period; and

All Market Participants Bonus Performance is the sum of the results of calculating Formula 1 of this subsection (g) for all Market Participants that have Bonus Performance during such Performance Assessment Interval.

(h) The provisions of this section 10A shall apply during the 2016/2017 Delivery Year, provided that:

(i) Non-Performance Charges shall be determined solely for and assessed solely on, Capacity Performance Resources committed for such Delivery Year;
(ii) The Non-Performance Charge shall be 0.5 times the Non-Performance Charge calculated under subsection (e) hereof; and
(iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.75 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(i) The provisions of this section 10A shall apply during the 2017/2018 Delivery Year, provided that:

(i) Non-Performance Charges shall be determined solely for, and assessed solely on, Capacity Performance Resources committed for such Delivery Year;

(ii) The Non-Performance Charge shall be 0.6 times the Non-Performance Charge calculated under subsection (e) hereof; and

(iii) The Non-Performance Charge Limit for a Delivery Year shall be 0.9 times Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times 365.

(j) The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year. Notwithstanding, if there are less than six months remaining in the current Delivery Year for which no invoice has been issued, the Office of the Interconnection may, with prior notice to PJM Members, allocate in equal amounts any Non-Performance Charge in the remaining monthly bills for the current Delivery Year plus up to six monthly bills into the following Delivery Year for all Capacity Market Sellers that incur such a Non-Performance Charge (but in no event shall the total Non-Performance Charge be divided in more than nine monthly bills). Provided, for any Non-Performance Charges associated with Performance Assessment Intervals from December 23, 2022 and December 24, 2022, a Capacity Market Seller may elect, by providing notice to the Office of Interconnection by March 17, 2023, to divide the total amount of Non-Performance Charges by either (i) the number of remaining monthly bills in the current Delivery Year (i.e., 3 bills) or (ii) the number of remaining monthly bills in the current Delivery Year plus six additional monthly bills into the following Delivery Year (i.e., 9 bills); provided further, however, that for an election under subsection (ii) above, the monthly Non-Performance Charge shall be levelized to include interest for the six month period following the current Delivery Year, such interest amount being determined at the electric interest rate established by the Federal Energy Regulatory Commission at the time of such election. All interest collected in accordance with this provision shall be allocated to the total pool of bonus performance payments and distributed in accordance with Tariff, Attachment DD, section 10A(g).

11. [Reserved for future use]

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of RAA, Schedule 6. Capitalized terms used herein that are not otherwise defined in Tariff, Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of

Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and

- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined as:

(1) for Delivery Years through the 2024/2025 Delivery Year, as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement.

Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer or winter) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer or winter Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)
>
> Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:
>
> (WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources – all provisions in RAA, Schedule 6, section L and Tariff, Attachment DD-1, section L shall be effective only through the 2025/2026 Delivery Year. Thereafter, no Energy Efficiency Resources shall qualify to be offered into the RPM Auctions beginning with the 2026/2027 Delivery Year.

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the end-use customer's retail site that is not reflected in the peak load forecast prepared for

the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable

Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(i) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(d) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by

a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Operating Agreement, Schedule 1, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 below, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section Operating Agreement, Schedule 1, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection‘s Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Economic Load Response Participant resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource‘s expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource‘s expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy

Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market performance-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the Regulation market performance-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the Regulation market performance-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market performance-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = \underset{\delta=0 \text{ to } 5\text{ Min}}{r_{\text{Signal,Response}(\delta,\delta+5\text{ Min})}};$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

Delay Score = Abs ((δ- 5 Minutes) / (5 Minutes)).

The Office of the Interconnection shall calculate an energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

Energy Score = 1 - 1/n $\sum$ Abs (Error);

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the Real-time Settlement Interval accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

(l) During a Market Suspension where the suspension is less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than twenty-four (24) consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource's Regulation clearing cost is determined by the summation of their Regulation offer and opportunity cost. The opportunity cost will be based on the resource's cost-based offer and will be determined as follows:

For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.

For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement

Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation accuracy score cannot be calculated during a Market Suspension, the 100-hour rolling average accuracy score will be used for the Market Suspension period.

(ii) If the regulation mileage ratio cannot be calculated during a Market Suspension, the mileage ratio will be set to one (1) for the Market Suspension period.

If the unit-specific benefits factor cannot be calculated during a Market Suspension, the unit-specific benefits factor would be based on the historical average unit-specific benefits factor over past hours that shared the same penetration of Regulation D resources that exist for the given Market Suspension hour.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 below do not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Reserve Requirements, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in section 3.2.3(n) below, if the total offered price for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead

Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve credit.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Operating Reserve credit shall be reduced by the greater of zero or the difference of the resource's Day-ahead Operating Reserve Target and the Balancing Operating Reserve Target, as determined below.

A resource's Day-ahead Operating Reserve Target shall be determined in accordance with the following equation:

(A + B) - C

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's Balancing Operating Reserve Target shall be determined in accordance with the following equation:

D – (E + F)

Where:

D = the sum of Start-up Costs and No-load Costs and the incremental cost of energy summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the

Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

F = the sum of all revenues earned for providing Secondary Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Operating Agreement, Schedule 1, section 3.2.3(p) below, 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. Allocation to real-time load share under this subsection (b) shall not apply to Direct Charging Energy.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Operating Agreement, Schedule 1, section 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) excluding Direct Charging Energy), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources) costs for generation resources.

Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), the output of which is reduced or suspended (or, for Energy Storage Resource Model Participants, the charging of which is increased) at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3(f).

(ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts

committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource 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 or solar generating units, Hybrid Resource or Energy Storage Resource as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-5) If a Market Participant of an Energy Storage Resource Model Participant believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. 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 Participant 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-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

(A x B) - C

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-6)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section 3.2.3(f-4), plus any cancellation fees paid in accordance with Operating Agreement, Schedule 1, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead

Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in section 3.2.3(q) below, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the

PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by section 3.2.3.(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Operating Agreement, Schedule 1, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$Ramp\_Request_t = \frac{(Dispatchtarget_{t-1} - AOutput_{t-1})}{(LAtime_{t-1})}$$

$$RL\_Desired_t = AOutput_{t-1} + (Ramp\_Request_t * Case\_Eff\_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the dispatch signal and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the dispatch LMP Desired MW for each Real-time Settlement Interval.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its % off dispatch is <= 10, or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh –Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Day-ahead MWh.

- For resources that are not dispatchable in both the Day-ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic Load Response Participant resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Operating Agreement, Schedule 1, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Operating Agreement, Schedule 1, section 3.2.3(h) except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. Allocation to real-time load share under this subsection (p) shall not apply to Direct Charging Energy. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, section 1.11.6, the Office of the Interconnection shall allocate the charges to the ratio share of real-time load plus export transactions.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceeds the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Operating Agreement, Schedule 1, section 3.2.3(h)(ii)(A) to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with section 3.2.3(p). Allocation to real-time load share under this subsection (q)(i) shall not apply to Direct Charging Energy.

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, section 3.2.3(q)(i). 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). Allocation to real-time load share under this subsection (q)(ii) shall not apply to Direct Charging Energy.

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than $2,000/MWh, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under Operaring Agreement, Schedule 1, section 6.4.3. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide..

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve

Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Market Clearing Prices exist, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Market Clearing Price to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic

Load Response Participant resources.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange

Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource’s energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource’s energy expected output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource’s energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource’s expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional Condense Energy Use in excess of day-ahead Condense Energy Use in real-time multiplied by A] plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B + C + D) – (E + F + G + H)

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve the resource was directed to deploy, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. For each Real-time Settlement Interval where there is not a Synchronized Reserve Event, the megawatts that will be charged shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, or the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that was assigned or self-scheduled for Synchronized Reserve and provided more Synchronized Reserve than it was directed to deploy will be used to offset the performance of other resources that provided less assigned or self-scheduled Synchronized Reserve than they were directed to deploy during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for

Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced 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 an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Economic Load Response Participant resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the

Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Non-Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Non-Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Non-Synchronized Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Non-Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Non-Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Non-Synchronized Reserve Market Clearing Prices exist, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the Non-Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning Non-Synchronized Reserves.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multipled by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Primary Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non- Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Secondary Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Market Clearing Prices exist, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary Reserve Market Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone .

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants’ response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional Condense Energy Use in excess of day-ahead Condense Energy Use multiplied by A plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero.

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B) – (C + D + E + F)

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from a steam-electric generating unit, a Hybrid Resource, or a combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output (or the level of Energy Storage Resource Model Participant charging withdrawals) requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level (or the level of Energy Storage Resource Model Participant charging withdrawals) if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from a steam-electric generating unit, a Hybrid Resource, combined cycle unit, or a combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the

Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) 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 ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

6.6 Minimum Generator Operating Parameters – Parameter Limited Schedules.

(a) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on cost-based offers, which are always parameter limited. Such offers must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such cost-based offers ("parameter limited schedules") shall be considered in the commitment of a resource when the Market Seller does not pass the three pivotal supplier test, as further described in Operating Agreement, Schedule 1, section 6.4.1 and the parallel provisions in Tariff, Attachment K-Appendix, section 6.4.1.

(b) Market Sellers submitting Offer Data for Generation Capacity Resources shall submit and be subject to pre-determined limits on market-based offers conforming to parameter limitations ("parameter limited schedules"). Such market-based parameter limited schedules must specify parameter values equal to or less limiting, i.e. more flexible, than the defined parameter limits. Such market-based parameter limited schedules shall be considered in the commitment of a resource under the following circumstances:

(i) For Capacity Performance Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert, Hot Weather Alert, Cold Weather Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert for all, or any part, of an Operating Day.

(c) For Capacity Performance Resources, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual unit on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters:

(i) Turn Down Ratio;

(ii) Minimum Down Time;

(iii) Minimum Run Time;

(iv) Maximum Daily Starts;

(v) Maximum Weekly Starts;

(vi) Maximum Run Time;

(vii) Start-up Time; and

(viii) Notification Time.

These unit-specific values shall apply for the generating unit unless it is operating pursuant to an exception from those values under subsection (i) hereof due to operational limitations that prevent the unit from meeting the minimum parameters. Throughout the analysis process, the Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's unit-specific parameter limited schedule values.

In order to make its determination of the unit-specific parameter limited schedule values for a unit, the Office of the Interconnection may request that the Capacity Market Seller provide to it and the Market Monitoring Unit certain data and documentation as further detailed in the PJM Manuals. Once the Office of the Interconnection has made a determination of the unit-specific parameter limited schedule values for a unit, those values will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed based on changed operational capabilities of the unit.

A Capacity Market Seller that does not believe its generating unit can meet the unit-specific values determined by the Office of the Interconnection due to actual operating constraints, and who desires to establish adjusted unit-specific parameters for those units may request adjusted unit-specific parameter limitations. Any such request must be submitted to the Office of the Interconnection by no later than the February 28 immediately preceding the first Delivery Year for which the adjusted unit-specific parameters are requested to commence. Capacity Market Sellers shall supply, for each generating unit, technical information about the operational limits to support the requested parameters, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a unit's request for adjusted unit-specific parameter limited schedule values. After it has completed its evaluation of the request, the Office of the Interconnection shall notify the Capacity Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied, by no later than April 15. The effective date of the request, if approved by the Office of the Interconnection, shall be no earlier than June 1.

The operational limitations referenced in this section 6.6 shall be (a) physical operational limitations based on the operating design characteristics of the unit, or (b) other actual physical constraints, including those based on contractual limits, that are not based on the characteristics of the unit. In order for a contractual or other actual constraint to be deemed a physical constraint that can be reflected in its unit-specific parameter limits for a Generation Capacity Resource, the Capacity Market Seller must demonstrate that contractual or other actual constraint is not simply an economic decision but a physical restriction that could not be rectified among any commercial alternatives actually available to it.

(d) [Reserved]

(e) [Reserved]

(f) [Reserved]

(g) The following additional parameter limits shall apply for Capacity Performance Resources, other than Capacity Storage Resources, submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Capacity Performance Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) The combined start-up and notification times shall not exceed 24 hours, except when a Hot Weather Alert or Cold Weather Alert has been issued;

(ii) When a Hot Weather Alert or Cold Weather Alert has been issued, combined start-up and notification times shall not exceed 14 hours;

(iii) When a Hot Weather Alert or Cold Weather Alert has been issued, notification time shall not exceed one hour; and,

(iv) When a Hot Weather Alert or Cold Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Capacity Performance Resource for both its market-based schedules and cost-based schedules.

Capacity Storage Resources that clear in a Reliability Pricing Model Auction shall, unless the Capacity Market Seller has requested for its Capacity Storage Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and notification time, and/or minimum down time, due to actual operating constraints pursuant to the process described in subsection (c) above:

(i) Have combined start-up and notification times that shall not exceed one hour; and,

(ii) Have a minimum down time that shall not exceed one hour.

(h) [Reserved]

(i) If a generating unit is or will become unable to achieve the default or unit-specific values determined by the Office of the Interconnection due to actual operating constraints affecting the unit, the Capacity Market Seller of that unit may submit a written request for an exception to the application of those values. Exceptions to the parameter limited schedule default or unit-specific values shall be categorized as either a one-time temporary exception, lasting 30 days or less; a period exception, lasting at least 31 days and no more than one year; or a persistent exception, lasting for at least one year.

(i) Temporary Exceptions. A temporary exception shall be deemed accepted without prior review by the Market Monitoring Unit or the Office of the Interconnection upon submission by the Market Seller of the generating unit of written notification to the Market Monitoring Unit and the Office of the Interconnection, and shall automatically commence and terminate on the dates specified in such notification, which must be for a period of time lasting 30 days or less, unless the termination date is extended pending a request for a period exception or shortened due to a change in the physical conditions of the unit such that the temporary exception is no longer required. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection within three days following the commencement of the temporary exception its documentation explaining in detail the reasons for the temporary exception, and shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Failure to provide a timely response to such request for additional information shall cause the temporary exception to terminate the following day. The Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing of any updates to the physical condition of the unit and shall notify the Office of Interconnection and the Market Monitoring Unit in writing of an early termination of a temporary exception due to changed physical conditions by no later than one Business Day prior to the early termination date. A Market Seller shall provide supporting documentation demonstrating the actual termination date of the physical and actual parameter limitation that prompted the need for the temporary exception to the Office of Interconnection and the Market Monitoring Unit within one Business Day of the termination of such condition. A temporary exception may only be requested one-time for the same physical and actual constraint per occurrence since an operational constraint that may periodically exist more than once should be the subject of a period exception request rather than multiple temporary exception requests.

In addition, if a Market Seller is unaware of the need for a period exception prior to the February 28 deadline for submitting such requests, the Market Seller may utilize the temporary exception process and seek to modify that exception pursuant to the process described below.

Modification of Temporary Exceptions. If, prior to the scheduled termination date the Market Seller determines that the temporary exception must persist for more than 30 days and the Market Seller wants to extend the period for which the exception applies, or if a Market Seller is unaware of the need for a period or persistent exception prior to the February 28 deadline for submitting such requests and the Market Seller has submitted a temporary exception request, it must submit to the Market Monitoring Unit and the Office of the Interconnection a written request to modify the temporary exception to become a period exception or a persistent exception, and provide detailed documentation explaining the reasons for the requested modification of the temporary exception. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period or persistent exception request, and if the exception requested is based on new physical operating limits for the unit for which some or all historical operating data is unavailable, the Market Seller may also submit technical information about the physical operational limits of the unit to support the requested parameters. Such Market Seller shall respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection within three Business Days after such request. Such request shall be reviewed by the Market Monitoring Unit and must be evaluated by the Office of the Interconnection using the same standard utilized to evaluate period exception and persistent exception requests. Per Tariff, Attachment M-Appendix, section II.B, the Market Monitoring Unit shall evaluate the modification request and provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request. The Office of the Interconnection shall provide its determination whether the request complies with the Tariff and Manuals by no later than 20 Business Days from the date of the modification request. A temporary exception shall be extended and shall not terminate until the date on which the Office of the Interconnection issues its determination of the modification request.

(ii) Period Exceptions and Persistent Exceptions. Market Sellers must submit period exception and persistent exception requests to the Market Monitoring Unit and the Office of the Interconnection by no later than the February 28 immediately preceding the twelve month period from June 1 to May 31 during which the exception is requested to commence. Market Sellers shall supply for each generating unit the required historical unit operating data in support of the period exception or persistent exception request, and if the exception requested is based on new physical operational limits for the unit for which some or all historical operating data is unavailable, the generating unit may also submit technical information about the physical operational limits for exceptions of the unit to support the requested parameters. The Market Monitoring Unit shall evaluate such request in accordance with the process set forth in Tariff, Attachment M-Appendix, section II.B. A Market Seller (i) must submit a parameter limited schedule value consistent with an agreement with the Market Monitoring Unit under such process or (ii) if it has not agreed with the Market Monitoring Unit on the parameter limited schedule value, may submit its own value to the Office of the Interconnection and to the Market Monitoring Unit, by no later than April 8. Each exception request must indicate the expected duration of the requested exception including the termination date thereof. The proposed parameter limited schedule value submitted by the Market Seller is subject to approval of the Office of the Interconnection pursuant to the requirements of the Tariff and the PJM Manuals. The Office of the Interconnection may engage the services of a consultant with technical expertise to evaluate the exception request. After it has completed its evaluation of the exception request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the exception request is approved or denied, by no later than April 15. The effective date of the exception, if approved by the Office of the Interconnection, shall be no earlier than June 1 of the applicable

Delivery Year. The Office of the Interconnection's determination for an exception shall continue for the period requested and, if requested, for such longer period as the Office of the Interconnection may determine is supported by the data.

The Market Seller shall provide written notification to the Market Monitoring Unit and the Office of the Interconnection of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection in their evaluations of the Market Seller's request for a period or persistent exception. The Market Monitoring Unit shall provide written notification to the Office of the Interconnection and the Market Seller of any change to its determination regarding the exception request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice. The Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, of any change to its determination regarding the exception request, based on the material change in facts, by no later than 20 Business Days after receipt of the Market Seller's notice. If the Office of the Interconnection determines that the exception no longer complies with the Tariff or Manuals, the following parameter values shall apply to all megawatts of the generating unit offered into the PJM energy markets:

(1) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply.

(2) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource and for which adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource adjusted unit-specific values shall apply.

(i) Notwithstanding the foregoing, the provisions of this section 6.6 shall only pertain to the Offer Data a Market Seller must submit to the Office of the Interconnection for its offers into the Day-ahead Energy Market, rebidding period that occurs after the clearing of the Day-ahead Energy Market and Real-time Energy Market, and do not affect or change in any way a Generation Owner's obligation under NERC Reliability Standards to notify the Office of the Interconnection of its actual or expected actual physical operating conditions during the Operating Day.

(k) Notwithstanding anything contrary herein, the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for a generating unit shall be applicable to that generating unit regardless whether there is a change in the owner, operator or Market Seller of the unit because the parameter limited schedule values for the unit are determined based on the physical limitations of the unit, which should not change merely based on a change in owners, operator or Market Seller. Because parameter limited schedule values attach to the generating unit and are not owned by a Market Seller of the unit, when there are multiple owners or Market Sellers for a generating unit, all owners and Market Sellers shall be bound by the unit-specific parameters, adjusted unit-specific parameters or exception to parameter limited schedule values determined by the Office of the Interconnection for the unit.

(l) The provisions of this section 6.6 only apply to Generation Capacity Resources, and not to Energy Resources.

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

"Accredited UCAP" shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

"Accredited UCAP Factor" shall mean, through the 2024/2025 Delivery Year, one minus EFORd, and for 2025/2026 Delivery Year and subsequent Delivery Years, the ratio of the Capacity Resource's Accredited UCAP to the Capacity Resource's installed capacity.

Agreement:

"Agreement" shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

"Annual Demand Resource" shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

"Applicable Regional Entity" shall have the same meaning as in the PJM Tariff.

Base Residual Auction:

"Base Residual Auction" shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Capacity Resource or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit" or "CETL" shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

"Capacity Only Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

"Capacity Performance Resource" shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

"Capacity Resources" shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and Reliability Assurance Agreement, Schedule 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; or (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.

Capacity Storage Resource Class:

"Capacity Storage Resource Class" shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours. The characteristic duration of an Energy Storage Resource Class is the ratio of the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

"Capacity Transfer Right" shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

"Coal Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

"Combination Resource" shall mean a Generation Capacity Resource that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

Compliance Aggregation Area (CAA):

"Compliance Aggregation Area" or "CAA" shall have the same meaning as in the Tariff.

Complex Hybrid Class:

"Complex Hybrid Class" shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Daily Unforced Capacity Obligation:

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

"Delivery Year" shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

"Demand Resource" or "DR" shall mean an Annual Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

“Demand Resource Registration” shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

Effective Nameplate Capacity:

“Effective Nameplate Capacity” shall mean (i) for each Variable Resource and Combination Resource, the resource’s Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output); (ii) for each Limited Duration Resource, the sustained level of output that the unit can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource’s capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

“Effective UCAP” shall mean a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Class:

"ELCC Class" shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

"ELCC Class Rating" shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

"ELCC Class UCAP" shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

"ELCC Portfolio UCAP" shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

"ELCC Resource" shall mean, through the 2024/2025 Delivery Year, a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource, and beginning with the 2025/2026 Delivery Year, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

"ELCC Resource Performance Adjustment" shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

"Electric Cooperative" shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

"Electric Distributor" shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

"Emergency" shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

"End-Use Customer" shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Members Committee sector classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Efficiency Resource:

"Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

“Exigent Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

“Existing Demand Resource” shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Facilities Study Agreement:

“Facilities Study Agreement” shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall have the meaning specified in the Tariff.

Firm Service Level:

“Firm Service Level” or “FSL” of Price Responsive Demand for the 2022/2023 Delivery Year and subsequent Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when an Emergency Action that triggers a Performance Assessment Interval is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. “Firm Service Level” or “FSL” of Demand Resource shall mean the pre-determined level for which an end-use customer’s load shall be reduced, upon notification from the Curtailment Service Provider’s market operations center or its agent.

Firm Transmission Service:

“Firm Transmission Service” shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

“Fixed Resource Requirement Alternative” or “FRR Alternative” shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

“Fixed-Tilt Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

“Forecast Pool Requirement” or “FPR” shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

“FRR Capacity Plan” or “FRR Plan” shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

“FRR Entity” shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

"FRR Service Area" shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

"Full Program Option" shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

"Full Requirements Service" shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

"Gas Combined Cycle Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

"Gas Combined Cycle Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

"Gas Combustion Turbine Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

"Gas Combustion Turbine Dual Fuel Class" shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

"Generation Capacity Resource" shall mean a Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Capacity Resource Provider:

"Generation Capacity Resource Provider" shall mean a Member that owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity.

Generation Owner:

"Generation Owner" shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

"Good Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hybrid Resource Class:

"Hybrid Resource Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in a Capacity Storage Resource Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

"Hydropower With Non-Pumped Storage" shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

"Hydropower With Non-Pumped Storage Class" shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

Incremental Auction:

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, Accredited UCAP Factor decrease, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Intermittent Hydropower Class:

"Intermittent Hydropower Class" shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

"IOU" shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Intermittent Landfill Gas Class:

"Intermittent Landfill Gas Class" shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Large Load Adjustment:

"Large Load Adjustment" shall mean any MW quantity of adjustments to summer peak load at the "zone/area" level and summed by Zone as further detailed in PJM Manuals. For purposes of this definition, a "zone/area" is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering (e.g., the service territory of an operating company of a Transmission Owner).

Limited Duration Resource:

"Limited Duration Resource" shall mean a Generation Capacity Resource that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Serving Entity or LSE:

"Load Serving Entity" or "LSE" shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

"Locational Reliability Charge" shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

"Markets and Reliability Committee" shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

"Maximum Emergency Service Level" or "MESL" of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

"Member" shall have the meaning provided in the Operating Agreement.

Members Committee:

"Members Committee" shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

Network External Designated Transmission Service:

"Network External Designated Transmission Service" shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

"Network Resources" shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Nominal PRD Value:

"Nominal PRD Value" shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

"Nominated Demand Resource Value" shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

"Non-Retail Behind the Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Nuclear Class:

"Nuclear Class" shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

"Obligation Peak Load" shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

"Office of the Interconnection" shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Offshore Wind Class:

"Offshore Wind Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

"Onshore Wind Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean that agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C, on file with the Commission.

Operating Day:

"Operating Day" shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

"Operating Reserve" shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Ordinary Water Storage:

"Ordinary Water Storage" shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

"Other Limited Duration Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

"Other Limited Duration Combination Class" shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

"Other Supplier" shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM's governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

"Other Unlimited Resource Class" shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

"Other Variable Resource Class" shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

"Partial Requirements Service" shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

"Party" shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

"Peak Shaving Adjustment" shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

"Percentage Internal Resources Required" shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Performance Assessment Interval:

"Performance Assessment Interval" shall have the meaning specified in Tariff, Attachment DD.

PJM:

"PJM" shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

"PJM Board" shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Manuals:

"PJM Manuals" shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Region:

"PJM Region" shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

"PJM Region Installed Reserve Margin" shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

"PJM Tariff," "Tariff," "O.A.T.T., "OATT" or "PJM Open Access Transmission Tariff" shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Planned Demand Resource:

"Planned Demand Resource" shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned External Generation Capacity Resource:

"Planned External Generation Capacity Resource" shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has a fully executed system impact study agreement (or other documentation which is functionally equivalent to a System Impact Study Agreement under the PJM Tariff) or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to a Facilities Study Agreement under the PJM Tariff), with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to an Interconnection Service Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

"Planned Generation Capacity Resource" shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, a System Impact Study Agreement (or, for resources for which a System Impact Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a System Impact Study Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, a Facilities Study Agreement (or, for resources for which a Facilities Study Agreement is not required, has such other agreement or documentation that is functionally equivalent to a Facility Studies Agreement) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

"Planning Period" shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

"Portfolio Expected Unserved Energy" shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

"PRD Curve" shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

"PRD Provider" shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider's Zonal Expected Peak Load Value of PRD:

"PRD Provider's Zonal Expected Peak Load Value of PRD" shall mean the expected contribution to Delivery Year peak load of a PRD Provider's Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year's peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection's load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

"PRD Reservation Price" shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

"PRD Substation" shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

"Price Responsive Demand" or "PRD" shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection (prior to 2022/2023Delivery Year) or a Performance Assessment Interval that triggers a PRD performance assessment (effective with 2022/2023 Delivery Year), and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

"Price Responsive Demand Credit" shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

“Price Responsive Demand Plan” or “PRD Plan” shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider’s Nominal PRD Value.

Public Power Entity:

“Public Power Entity” shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

“Qualifying Transmission Upgrades” shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” or “RERRA” shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

“Reliability Principles and Standards” shall mean the principles and standards established by the Office of the Interconnection that define, among other things, an acceptable probabilistic of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

“Required Approvals” shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

“Self-Supply” shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

“Small Commercial Customer” shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

"State Regulatory Structural Change" shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

Steam Class:

"Steam Class" shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

"Supervisory Control" shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

"Threshold Quantity" shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be determined in accordance with Reliability Assurance Agreement, Schedule 8.1, section D.2.

Tracking Solar Class:

"Tracking Solar Class" shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners

Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity:

"Unforced Capacity" shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

"Unlimited Resource" shall mean a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource:

"Variable Resource" shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

Winter Peak Load (or WPL):

"Winter Peak Load" or "WPL" shall mean the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand values may be excluded from the calculation. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

Zonal Capacity Price:

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

Zone or Zonal:

"Zone" or "Zonal" shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

"Zonal Winter Weather Adjustment Factor" or "ZWWAF" shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. Qualified Demand Resources generally fall in one of two categories, i.e., Guaranteed Load Drop or Firm Service Level, as further specified in section G below and the PJM Manuals. Qualified Demand Resources may be provided by a Curtailment Service Provider, notwithstanding that such Curtailment Service Provider is not a Party to this Agreement. Such Curtailment Service Providers must satisfy the requirements hereof and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section F hereof, as applicable, the Office of the Interconnection of the Demand Resource Registration that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the Demand Resource Registration is linked to a Summer-Period Demand Resource or an Annual Demand Resource.

2. A Demand Resource Registration must achieve its full load reduction within the following time period:

(a) For the 2015/2016 Delivery Year and subsequent Delivery Years, a Demand Resource Registration must be able to fully respond to a Load Management Event within 30 minutes of notification from the Office of the Interconnection. This default 30 minute prior notification shall apply unless a Curtailment Service Provider obtains an exception from the Office of the Interconnection due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe. In such case, the Curtailment Service Provider shall submit a request for an exception to the 30 minute prior notification requirement to the Office of the Interconnection, at the time the Registration Form for that Demand Resource Registration is submitted in accordance with Tariff, Attachment K-Appendix. The only alternative notification times that the Office of Interconnection will permit, upon approval of an exception request, are 60 minutes and 120 minutes prior to a Load Management Event. The Curtailment Service Provider shall indicate in writing, in the appropriate application, that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. A Curtailment Service Provider shall not submit a request for an exception to the default 30 minute notification period unless it has done its due diligence to confirm that the Demand Resource Registration is physically incapable of responding within that timeframe based on one or more of the reasons set forth below and as may be further defined in the PJM Manuals and has obtained detailed data and documentation to support this determination.

In order to establish that a Demand Resource Registration is reasonably expected to be physically unable to reduce load in that timeframe, the Curtailment Service Provider that submitted the Demand Resource Registration must demonstrate that:

(i) The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;

(ii) Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes;

(iii) On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,

(iv) The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

The Office of the Interconnection may request data and documentation from the Curtailment Service Provider and such Curtailment Service Provider shall provide to the Office of the Interconnection within three (3) Business Days of a request therefor, a copy of all of the data and documentation supporting the exception request. Failure to provide a timely response to such request shall cause the exception to terminate the following Operating Day.

At its sole option and discretion, the Office of the Interconnection may review the data and documentation provided by the Curtailment Service Provider to determine if the Demand Resource Registration has met one or more of the criteria above. The Office of the Interconnection will notify the Curtailment Service Provider in writing of its determination by no later than ten (10) Business Days after receipt of the data and documentation.

The Curtailment Service Provider shall provide written notification to the Office of the Interconnection of a material change to the facts that supported its exception request within three (3) Business Days of becoming aware of such material change in facts, and, if the Office of Interconnection determines that the physical limitation criteria above are no longer being met, the Demand Resource Registration shall be subject to the default notification period of 30 minutes immediately upon such determination.

3. The initiation of load reduction, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered a pre-emergency or emergency action and must be implementable prior to a voltage reduction.

5. A Curtailment Service Provider intending to offer for sale or designate for self-supply, a Demand Resource in any RPM Auction, or intending to include a Demand Resource in any FRR Capacity Plan must demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. As part of such demonstration, each such Curtailment Service Provider shall submit a Demand Resource Sell Offer Plan in accordance with the standards and procedures set forth in RAA, Schedule 6, section A-1; RAA, Schedule 8.1 (as to FRR Capacity Plans) and the PJM Manuals, no later than 30 days prior to, as applicable, the RPM Auction in which such resource is to be offered, or the deadline for submission of the FRR Capacity Plan in which such resource is to be included. PJM may verify the Curtailment Service Provider's adherence to the Demand Resource Sell Offer Plan at any time. A Curtailment Service Provider with a PJM-approved Demand Resource Sell Offer Plan will be permitted to offer up to the approved Demand Resource quantity into the subject RPM Auction or include such resource in its FRR Capacity Plan.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be linked to registrations participating in the Full Program Option or Capacity Only Option of the Emergency Load Response and Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared pre-emergency events and emergency events.

A-1. A Demand Resource Sell Offer Plan shall consist of a completed template document in the form posted on the PJM website, requiring the information set forth below and in the PJM Manuals, and a Demand Resource Officer Certification Form signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification. The Demand Resource Sell Offer Plan must provide information that supports the Demand Resource Provider's intended Demand Resource Sell Offers and demonstrates that the Demand Resources are being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource registrations for the relevant Delivery Year. The Demand Resource Sell Offer Plan shall include all Existing Demand Resources and all Planned Demand Resources that the Demand Resource Provider intends to offer into an RPM Auction or include in an FRR Capacity Plan.

1. Demand Resource Sell Offer Plan Template. The Demand Resource Sell Offer Plan template, in the form provided on the PJM website, shall require the Demand Resource Provider to provide the following information and such other information as specified in the PJM Manuals:

(a) Summary Information. The completed template shall include the Demand Resource Provider's company name, contact information, and the Nominated DR Value in ICAP MWs by Zone/sub-Zone that the Demand Resource Provider intends to offer, stated separately for Existing Demand Resources and Planned Demand Resources. The total Nominated DR Value in MWs for each Zone/sub-Zone shall be the sum of the Nominated DR Value of Existing Demand Resources and the Nominated DR Value of Planned Demand Resources, and shall be the maximum MW amount the Provider intends to offer in the RPM Auction for the indicated Zone/sub-Zone, provided that nothing herein shall preclude the Demand Resource Provider from offering in the auction a lesser amount than the total Nominated DR Value shown in its Demand Resource Sell Offer Plan.

(b) Existing Demand Resources. The Demand Resource Provider shall identify all Existing Demand Resources by identifying end-use customer sites that are currently registered with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the auction Delivery Year.

(c) Planned Demand Resources. The Demand Resource Provider shall provide the details of, and key assumptions underlying, the Planned Demand Resource quantities (i.e., all Demand Resource quantities in excess of Existing Demand Resource quantities) contained in the Demand Resource Sell Offer Plan, including:

(i) key program attributes and assumptions used to develop the Planned Demand Resource quantities, including, but not limited to, discussion of:

- method(s) of achieving load reduction at customer site(s);
- equipment to be controlled or installed at customer site(s), if any;
- plan and ability to acquire customers;
- types of customer targeted;
- support of market potential and market share for the target customer base, with adjustments for Existing Demand Resource customers within this market and the potential for other Demand Resource Providers targeting the same customers; and
- assumptions regarding regulatory approval of program(s), if applicable.

(ii) Zone/sub-Zone information by end-use customer segment for all Nominated DR Values for which an end-use customer site is not identified, to include the number in each segment of end-use customers expected to be registered for the subject Delivery Year, the average Peak Load Contribution per end-use customer for such segment, and the average Nominated DR Value per customer for such segment. End-use customer segments may include residential, commercial, small industrial, medium industrial, and large industrial, as identified and defined in the PJM Manuals, provided that nothing herein or in the Manuals shall preclude the Provider from identifying more specific customer segments within the commercial and industrial categories, if known.

(iii) Information by end-use customer site to the extent required by subsection A-1(1)(c)(iv) or, if not required by such subsection, to the extent known at the time of the submittal of the Demand Resource Sell Offer Plan, to include: customer EDC account number (if known), customer name, customer premise address, Zone/sub-Zone in which the customer is located, end-use customer segment, current Peak Load Contribution value (or an estimate if actual value not known) and an estimate of expected Peak Load Contribution for the subject Delivery Year, and an estimated Nominated DR Value.

(iv) End-use customer site-specific information shall be required for any Zones or sub-Zones identified by PJM pursuant to this subsection for the portion, if any, of a Demand Resource Provider's intended offer in such Zones or sub-Zones that exceeds a Sell Offer threshold determined pursuant to this subsection, as any such excess quantity under such conditions should reflect Planned Demand Resources from end-use customer sites that the Provider has a high degree of certainty it will physically deliver for the subject Delivery Year. In accordance with the procedures in subsection A-1(3) below, PJM shall identify, as requiring site-specific information, all Zones and sub-Zones that comprise any LDA group (from a list of LDA groups stated in the PJM Manuals) in which [the quantity of cleared Demand Resources from the most recent Base Residual Auction] plus [the quantity of Demand Resources included in FRR Capacity Plans for the Delivery Year addressed by the most recent Base Residual Auction] in any Zone or sub-Zone of such LDA group exceeds the greater of:

- the maximum Demand Resources quantity registered with PJM for such Zone for any Delivery Year from the current (at time of plan submission) Delivery Year and the two preceding Delivery Years; and

- the potential Demand Resource quantity for such Zone estimated by PJM based on an independent published assessment of demand response potential that is reasonably applicable to such Zone, as identified in the PJM Manuals.

For each such Zone and sub-Zone, the Sell Offer threshold for each Demand Resource Provider shall be the higher of:

- the Demand Resource Provider's maximum Demand Resource quantity registered with PJM for such Zone/sub-Zone over the current Delivery Year (at the time of plan submission) and two preceding Delivery Years;

- the Demand Resource Provider's maximum for any single Delivery Year of [such provider's cleared Demand Resource quantity] plus [such provider's quantity of Demand Resources included in FRR Capacity Plans] from the three forward Delivery Years addressed by the three most recent Base Residual Auctions for such Zone/sub-Zone; and

- 10 MW.

(d) Schedule. The Demand Resource Provider shall provide an approximate timeline for procuring end-use customer sites as needed to physically deliver the total Nominated DR Value (for both Existing Demand Resources and Planned Demand Resources) by Zone/sub-Zone in the Demand Resource Sell Offer Plan. The Demand Resource Provider must specify the cumulative number of customers and the cumulative Nominated DR Value associated with each end-use customer segment within each Zone/sub-Zone that the Demand Resource Provider expects (at the time of plan submission) to have under contract as of June 1 each year between the time of the auction and the subject Delivery Year.

2. Demand Resource Officer Certification Form. Each Demand Resource Sell Offer Plan must include a Demand Resource Officer Certification, signed by an officer of the Demand Resource Provider that is duly authorized to provide such a certification, in the form shown in the PJM Manuals, which form shall include the following certifications:

(a) that the signing officer has reviewed the Demand Resource Sell Offer Plan and the information supplied to PJM in support of the Plan is true and correct as of the date of the certification;

(b) that the Sell Offer Plan does not include any Critical Natural Gas Infrastructure facilities, and

(c) that the Demand Resource Provider is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of the certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.

As set forth in the form provided in the PJM Manuals, the certification shall specify that it does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Demand Resource Provider's rights and obligations thereunder, including the Demand Resource Provider's ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

3. Procedures. No later than December 1 prior to the Base Residual Auction for a Delivery Year, PJM shall post to the PJM website a list of Zones and sub-Zones, if any, for which end-use customer site-specific information shall be required under the conditions specified in subsection A-1(1)(c)(iv) above for all RPM Auctions conducted for such Delivery Year. Once so identified, a Zone or sub-Zone shall remain on the list for future Delivery Years until the threshold determined under subsection A-1(1)(c)(iv) above is not exceeded for three consecutive Delivery Years. No later than 30 days prior to the RPM Auction in which a Demand Resource Provider intends to offer a Demand Resource, the Demand Resource Provider shall submit to PJM a completed Demand Resource Sell Offer Plan template and a Demand Resource Officer Certification Form signed by a duly authorized officer of the Provider. PJM will review all submitted DR Sell Offer Plans. No later than 10 Business Days prior to the subject RPM Auction, PJM shall notify any Demand Resource Providers that have identified the same end-use customer site(s) in their respective DR Sell Offer Plans for the same Delivery Year. In such event, the MWs associated with such site(s) will not be approved for inclusion in a Sell Offer in an RPM Auction by any of the Demand Resource Providers, unless a Demand Resource Provider provides a letter of support from the end-use customer indicating that it is likely to execute a contract with that Demand Resource Provider for the relevant Delivery Year, or provides other comparable evidence of likely commitment. Such letter of support or other supporting evidence must be provided to PJM no later than 7 Business Days prior to the subject RPM Auction. If an end-use customer provides letters of support for the same site for the same Delivery Year to multiple Demand Resource Providers, the MWs associated with such end-use customer site shall not be approved as a Demand Resource for any of the Demand Resource Providers. No later than 5 Business Days prior to the subject RPM Auction, PJM will notify each Demand Resource Provider of the approved Demand Resource quantity, by Zone/sub-Zone, that such Demand Resource Provider is permitted to offer into such RPM Auction.

B. The Unforced Capacity value of a Demand Resource will be determined:

(1) for Delivery Years through the 2024/2025 Delivery Year, as the product of the Nominated Value of the Demand Resource times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

(2) for the 2025/2026 Delivery Year and subsequent Delivery Years, in accordance with RAA, Schedule 9.2. Nominated Values shall be determined and reviewed in accordance with sections I and J, respectively, and the PJM Manuals.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Tariff, Attachment DD. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Curtailment Service Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Tariff, Attachment DD to the extent it fails to provide the resource in such location consistent with its cleared offer.

D. The Party, Electric Distributor, or Curtailment Service Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in section C for a committed Demand Resource, notwithstanding that such provider is not the customer's energy supplier.

E. Any Party hereto shall demonstrate that its Demand Resources performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section K hereof and the PJM Manuals. In addition, committed Demand Resources that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Tariff, Attachment DD.

F. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

G. PJM measures Demand Resource Registrations in the following ways:

Firm Service Level (FSL) – Load management achieved by an end-use customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Curtailment Service Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by an end-use customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Curtailment Service Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

H. Each Curtailment Service Provider must satisfy (or contract with another LSE, Curtailment Service Provider, or electric distribution company to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

- Supplemental status reports, detailing Demand Resources available, as requested by PJM;

- Entry of customer-specific Demand Resource Registration information, for planning and verification purposes, into the designated PJM electronic system.

- Customer-specific compliance and verification information for each PJM-initiated Demand Resource event or test event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

- Load drop estimates for all Load Management events and test events, prepared in accordance with the PJM Manuals.

I. The Nominated Values (summer or winter) for each Demand Resource Registration shall be determined consistent with the process described below.

The summer Nominated Value for Firm Service Level customer(s) on a registration will be based on the peak load contribution for the customer(s), as typically determined by the 5CP methodology utilized by the electric distribution company to determine ICAP obligation values. The summer Nominated Value for a registration shall equal the total peak load contribution for the customers on the registration minus the summer Firm Service Level multiplied by the loss factor. The winter Nominated Value for Firm Service Level customer(s) on a registration shall equal the total Winter Peak Load for customers on the registration multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service level and then the result is multiplied by the loss factor.

The summer Nominated Value for a Guaranteed Load Drop customer on a registrationshall equal the summer guaranteed load drop amount, adjusted for system losses and shall not exceed the customer's Peak Load Contribution, as established by the customer's contract with the Curtailment Service Provider. The winter Nominated Value for a Guaranteed Load Drop customer on a registration shall be the winter guaranteed load drop amount, adjusted for system losses, and shall not exceed the customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor, as established by the customer's contract with the Curtailment Service Provider.

Customer-specific Demand Resource Registration information (EDC account number, peak load contribution, Winter Peak Load, notification period, etc.) will be entered into the designated PJM electronic system to establish nominated values. Each Demand Resource Registration should be linked to a Demand Resource. Additional data may be required, as defined in sections J and K and the PJM Manuals.

J. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource Registration information, to verify the amount of load management available and to set a summer or winter, Nominated Value. Data is provided by both the zone EDC and the Curtailment Service Provider in the designated PJM electronic system, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), Winter Peak Load, contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for which such Demand Resource Registration is effective. Curtailment Service Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Curtailment Service Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

The daily Nominated Value of a Demand Resource with a Capacity Performance commitment (which may consist of an Annual Demand Resource with a Capacity Performance commitment and/or Summer Period Demand Resource with a Capacity Performance commitment) shall equal the sum of the summer Nominated Values of the registrations linked to such Demand Resource for the summer period of June through October and May of the Delivery Year, and shall equal the lesser of (i) the sum of the summer Nominated Values of the registrations linked to such Demand Resource or (ii) the sum of the winter Nominated Values of the registrations linked to such Demand Resource for the non-summer period of November through April of the Delivery Year.

K. Compliance is the process utilized to review Provider performance during PJM-initiated Load Management events and tests. Compliance will be established for each Provider on an event specific basis for the Curtailment Service Provider's Demand Resource Registrations dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Curtailment Service Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event and test during the compliance period.

Compliance is measured for Market Participant Bonus Performance, as applicable, and Non-Performance Charges. Non-Performance Charges are assessed for the defined obligation period of each Demand Resource as defined in RAA, Article 1, subject to the following requirements:

Compliance is checked on an individual customer basis for Firm Service Level, by comparing actual load during the event to the firm service level. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Curtailment Service Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

Summer (June through October and the following May of a Delivery Year)- End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

(PLC) - (Load *LF)

Winter (November through April of a Delivery Year)– End use customer's Winter Peak Load ("WPL") multiplied by Zonal Winter Weather Adjustment Factor ("ZWWAF") multiplied by LF, minus the metered load ("Load") multiplied by the LF. The calculation is represented by:

(WPL * ZWWAF * LF) – (Load * LF)

Compliance is checked on an individual customer basis for Guaranteed Load Drop. Current load for a statistical sample of end-use customers may be used for compliance for residential non-interval metered registrations in accordance with the PJM Manuals and subject to PJM approval. Guaranteed Load Drop compliance will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management Event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) For a summer event, the PLC minus the Load multiplied by the LF. A summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC. For a non-summer event, the WPL multiplied the ZWWAF multiplied by LF, minus the Load multiplied by the LF. A non-summer load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the WPL multiplied by the ZWWAF multiplied by LF.

(ii) Curtailment Service Providers must submit actual loads and comparison loads for all hours during the day of the Load Management Event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

(iii) Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers are described in greater detail in Manual M-19, PJM Manual for Load Forecasting and Analysis, at Attachment A: Load Drop Estimate Guidelines.

Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.

A Demand Resource Registration may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero.

For a Performance Assessment Interval, compliance will be totaled over all dispatched registrations for FSL and GLD customers linked to a Provider's Annual Demand Resource with a Capacity Performance commitment to determine the Actual Performance for such Demand Resource in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals. The Expected Performance for such Demand Resource shall be equal to the Provider's committed capacity on the Demand Resource, adjusted to account for any linked registrations that were not dispatched by PJM. A Provider's Demand Resources' initial Performance Shortfalls shall be netted for all the seller's Demand Resources in the Emergency Action Area to determine a net Emergency Action Area Performance Shortfall which is then allocated to the Capacity Market Seller's Demand Resources in accordance with Tariff, Attachment DD, section 10A, and PJM Manuals.

L. Energy Efficiency Resources – all provisions in RAA, Schedule 6, section L and Tariff, Attachment DD-1, section L shall be effective only through the 2025/2026 Delivery Year. Thereafter, no Energy Efficiency Resources shall qualify to be offered into the RPM Auctions beginning with the 2026/2027 Delivery Year.

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak summer and winter periods as described herein) reduction in electric energy consumption at the end-use customer's retail site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value.

- For the 2018/2019 Delivery Year and subsequent Delivery Years and for any Annual Energy Efficiency Resource committed as a Capacity Performance Resource, the seller's proposed Nominated Energy Efficiency Value for any Annual Energy Efficiency Resources, shall be the expected average load reduction, for all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 15:00 EPT and the hour ending 18:00 EPT. In addition, the expected average load reduction for all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and the hour ending 9:00 EPT and between the hour ending 19:00 EPT and the hour ending 20:00 EPT shall not be less than the Nominated Energy Efficiency Value; and

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the seller's proposed Nominated Energy Efficiency Value for any Summer-Period Energy Efficiency Resource shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday.

  The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Tariff, Attachment Q. The Unforced Capacity

value of an Energy Efficiency Resource offered into an RPM Auction or committed in a FRR Capacity Plan shall be the Nominated Energy Efficiency Value times the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in Tariff, Attachment DD, section 5.14(c).

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

8. For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, if a Relevant Electric Retail Regulatory Authority receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of the PJM Region, the following process applies:

(a) The Office of the Interconnection will publicly post a reference to the FERC authorization of a Relevant Electric Retail Regulatory Authority order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable electric distribution company(ies), and the applicable auction(s) and/or Delivery Year(s).

(b) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources that are located in the jurisdiction of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation within the Zone or LDA, as required, and those outside of the area but within the Zone or LDA, as required.

(c) A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all Energy Efficiency Resources to be offered as part of its Energy Efficiency measurement and verification plan and certified post-installation measurement and verification report. The Office of Interconnection will provide a list to the relevant electric distribution company for the specific area(s) to review for compliance with the Relevant Electric Retail Regulatory Authority of Capacity Market Sellers that are:

(ii) offering Energy Efficiency Resources in an RPM Auction within two (2) Business Days after the deadline for submitting an energy efficiency measurement and verification plan for such RPM Auction; and

(ii) certifying Energy Efficiency Resources with a Delivery Year post-installation measurement and verification report, within two (2) Business Days of receipt of such Delivery Year post-installation measurement and verification report.The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource.

(di) The relevant electric distribution company for the specific area(s) shall review for compliance with rules from a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation and provide a response to the Office of the Interconnection within five (5) Business Days after receiving the list of Capacity Market Sellers offering Energy Efficiency Resources. The Office of the Interconnection will not allow a Capacity Market Seller to offer or certify Energy Efficiency Resources if an electric distribution company denies such Capacity Market Seller to deliver Energy Efficiency Resources in compliance with rules of a Relevant Electric Retail Regulatory Authority authorized by FERC to qualify or prohibit Energy Efficiency Resource participation.

(9) For RPM Auctions for the 2021/2022 Delivery Year and subsequent Delivery Years, a Capacity Market Seller of Energy Efficiency Resources that cannot satisfy its RPM obligations in any Delivery Year due to the prohibition of participation by a Relevant Electric Retail Regulatory Authority authorized by FERC to prohibit participation of such resources may be relieved of its Capacity Resource Deficiency

Charge by notifying the Office of the Interconnection by no later than seven (7) calendar days prior to the posting of the planning parameters for the Third Incremental Auction of that Delivery Year. After providing such notice, the affected Capacity Market Seller may elect to be relieved of its RPM commitment, and shall not be required to obtain replacement capacity for the resource, and no charges shall be assessed by the Office of the Interconnection for the Capacity Market Seller's deficiency in satisfying its RPM obligation for the resource for such Delivery Year. In such case, however, the Capacity Market Seller shall not be entitled to, nor be paid, any RPM revenues for such resource for that Delivery Year. The Office of the Interconnection will apply corresponding adjustments to the quantity of Buy Bids or Sell Offers in the Incremental Auctions for such Delivery Years in accordance with Tariff, Attachment DD, sections 5.12(b)(ii) and 5.12(b)(iii).

C. Election, and Termination of Election, of FRR Alternative

1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. No later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources and Seasonal Capacity Performance Resources, as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, except a new FRR Entity's initial election, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

5. Notwithstanding subsections C.1 and C.2 of this Schedule, an FRR Entity that elected the FRR Alternative for a Delivery Year prior to the 2025/2026 Delivery Year, may terminate its election of the FRR Alternative prior to meeting the minimum term of five years without penalty by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for a Delivery Year through the 2028/2029 Delivery Year.

G. Capacity Resource Performance

1. Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

2. For any FRR Entity which opted to be subject to physical non-performance assessments under RAA, Schedule 8.1, section C.1, such FRR Entity will not be subject to charges under Tariff, Attachment DD, section 10A, but, rather, it will be required to update its FRR Capacity Plan with additional megawatts of Capacity Performance Resources or Seasonal Capacity Performance Resources determined in accordance with the following: For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's FRR Capacity Plan or Price Responsive Demand committed to reduce the FRR Entity's unforced capacity obligation (for the 2022/2023 Delivery Year and subsequent Delivery Years) will be determined in the same fashion as prescribed by the Tariff, Attachment DD, section 10A, and for such hour, a net Performance Shortfall shall be determined separately for Capacity Performance Resources and for Base Capacity Resources. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) exceeds the Expected Performance of such resources or Price Responsive Demand, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Base Capacity Resources for such hour. If, for a Performance Assessment Interval, the combined Actual Performance of all an FRR Entity's committed Base Capacity Resources exceeds the Expected Performance of such resources, then such over-performance may be applied to any Performance Shortfall experienced by such FRR Entity's Capacity Performance Resources or Price Responsive Demand committed by the FRR Entity (for the 2022/2023 Delivery Year and subsequent Delivery Years) for such hour. For the 2020/2021 Delivery Year, the net Performance Shortfall determined for Capacity Performance Resources and Price Responsive Demand shall include the performance of Seasonal Capacity Performance Resources contained in the FRR Capacity Plan.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources or Price Responsive Demand, if any, for each such Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval to establish the additional MW quantities of Capacity Performance Resources, Seasonal Capacity Performance Resources, or Price Responsive Demand that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Capacity Performance Resources in any Delivery Year shall not exceed a MW quantity equal to 0.5 times the MW quantity of the Capacity Performance Resources and Seasonal Capacity Performance Resources that were committed in the FRR Capacity Plan for such Delivery Year and Price Responsive Demand committed such Delivery Year (for the 2022/2023 Delivery Year and subsequent Delivery Years). The FRR Entity's net Performance Shortfall among Base Capacity Resources, if any, for each such Performance Assessment Interval shall be multiplied by a rate of [(0.00139 MWs/Performance Assessment Interval) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)] to establish the additional MW quantities of Capacity Performance Resources or Seasonal Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the next Delivery Year. Notwithstanding the foregoing, the total additional MWs required as a result of non-performance by the FRR Entity's Base Capacity Resources in any Delivery Year shall not exceed a MW quantity equal to [(0.5 times the MW quantity of the Base Capacity Resources that were committed in the FRR Capacity Plan for such Delivery Year) times (the Base Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions, divided by the Net CONE established for such LDA for the Delivery Year)].

An FRR Entity that elects the physical option shall not be eligible for, or subject to, the revenue allocation described in Tariff, Attachment DD, section 10A(g).

H. Annexation of service territory by Public Power Entity

1. In the event a Public Power Entity that is an FRR Entity annexes service territory to include new customers on sites where no load had previously existed, then the incremental load on such a site shall be treated as unanticipated load growth, and such FRR Entity shall be required to commit sufficient resources to cover such obligation in the relevant Delivery Year.

2. In the event a Public Power Entity that is an FRR Entity annexes service territory to include load from a Party that has not elected the FRR Alternative, then:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, such acquiring FRR Entity shall pay a Locational Reliability Charge for the acquired load.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, such acquiring FRR Entity shall include such incremental load in its FRR Capacity Plan.

3. Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR Entity:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, PJM would consider shifted load as unanticipated load growth for purposes of determining the RTO/LDA Reliability Requirements, and such shifted load shall pay a Locational Reliability Charge. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, the FRR Entity that lost such load would no longer include such load in its FRR Capacity Plan, and PJM would include such shifted load in future BRAs.

Attachment C

GDECS – Chart of Proposed Clean-Ups, Clarifications and Corrections to the PJM Open Access Transmission Tariff, PJM Operating Agreement and PJM Reliability Assurance Agreement

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
1.	Tariff, Definitions, A-B	**Base Capacity Demand Resource:** "Base Capacity Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.	~~**Base Capacity Demand Resource:**~~ ~~"Base Capacity Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 49; RAA, Article 1 – Definitions.
2.	Tariff, Definitions, A-B	**Base Capacity Demand Resource Constraint:** "Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based	~~**Base Capacity Demand Resource Constraint:**~~ ~~"Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].	~~Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.~~ ~~For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM~~	

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
			~~Region or such LDA, reduced by the amount of load served under the FRR Alternative].~~	
3.	Tariff, Definitions, A-B	**Base Capacity Energy Efficiency Resource:** "Base Capacity Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.	~~**Base Capacity Energy Efficiency Resource:**~~ ~~"Base Capacity Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 50; RAA, Article 1 – Definitions.
4.	Tariff, Definitions, A-B	**Base Capacity Resource:** "Base Capacity Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).	~~**Base Capacity Resource:**~~ ~~"Base Capacity Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
5.	Tariff, Definitions, A-B	**Base Capacity Resource Constraint:** "Base Capacity Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load	~~**Base Capacity Resource Constraint:**~~ ~~"Base Capacity Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings. For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery	~~first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.~~ ~~For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment~~	

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].	~~of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].~~	
6.	Tariff, Definitions, C-D	**Capacity Performance Transition Incremental Auction:** "Capacity Performance Transition Incremental Auction" shall have the meaning specified in Tariff, Attachment DD, section 5.14D.	~~**Capacity Performance Transition Incremental Auction:**~~ ~~"Capacity Performance Transition Incremental Auction" shall have the meaning specified in Tariff, Attachment DD, section 5.14D.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. No information on Capacity Performance Transitional Incremental Auction in Tariff, Attachment DD, section

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
				5.14D. Information was already removed from Tariff. *See PJM Interconnection, L.L.C.*, Commission Delegated Letter Order, Docket Nos. ER23-1265-000 *et al.* (June 6, 2023).
7.	Tariff, Definitions, C-D	**Demand Resource Factor or DR Factor:** "Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.	~~**Demand Resource Factor or DR Factor:**~~ ~~"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 53; RAA, Article 1 – Definitions.
8.	Tariff, Definitions, E-F	**Extended Summer Demand Resource:** "Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.	~~**Extended Summer Demand Resource:**~~ ~~"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 55; RAA, Article 1 – Definitions.
9.	Tariff, Definitions, L-M-N	**Limited Demand Resource:** **"**Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.	~~**Limited Demand Resource:**~~ ~~"Limited Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 56;

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
				RAA, Article 1 – Definitions.
10.	Tariff, Definitions, L-M-N	**Limited Demand Resource Reliability Target:** "Limited Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly	~~Limited Demand Resource Reliability Target:~~ ~~"Limited Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].	~~relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is~~	

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
			~~converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].~~	
11.	Tariff, Definitions, L-M-N	**Limited Resource Constraint:** "Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.	~~**Limited Resource Constraint:**~~ ~~"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.
12.	Tariff, Definitions, L-M-N	**Minimum Annual Resource Requirement:** "Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the	~~**Minimum Annual Resource Requirement:**~~ ~~"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative	~~Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative~~	
13.	Tariff, Definitions L-M-N	**Minimum Extended Summer Resource Requirement:** "Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.	~~**Minimum Extended Summer Resource Requirement:**~~ ~~"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
14.	Tariff, Definitions L-M-N	MOPR Floor Offer Price: "MOPR Floor Offer Price" shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).	MOPR Floor Offer Price: "MOPR Floor Offer Price" shall mean a minimum offer price applicable to certain Market Seller's Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, section~~s 5.14(h), 5.14(h-1), and~~ 5.14(h-2).	Tariff, Attachment DD, sections 5.14(h) and (h-1) have passed sunset date and are no longer relevant under the Capacity Performance construct. *See* Row 38; Tariff, Att. DD, Sections 5.14 (h) & (h-1).
15.	Tariff, Definitions O-P-Q	**Performance Assessment Interval:** "Performance Assessment Interval" shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September.	**Performance Assessment Interval:** "Performance Assessment Interval" shall mean each Real-time Settlement Interval for which an Emergency Action has been declared by the Office of the Interconnection~~, provided, however, that Performance Assessment Intervals for a Base Capacity Resource shall not include any intervals outside the calendar months of June through September~~.	Base Capacity Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
16.	Tariff, Definitions R-S	**Reliability Pricing Model Auction:** "Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.	**Reliability Pricing Model Auction:** "Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction~~, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction~~.	Capacity Performance Transition Incremental Auction term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
				contained within the affected language.
17.	Tariff, Definitions R-S	**Short-Term Resource Procurement Target:** "Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA	~~**Short-Term Resource Procurement Target:**~~ ~~"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.
18.	Tariff, Definitions R-S	**Short-Term Resource Procurement Target Applicable Share:** "Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for	~~**Short-Term Resource Procurement Target Applicable Share:**~~ ~~"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target	~~PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target~~	
19.	Tariff, Definitions S-T	**Sub-Annual Resource Constraint:** "Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.	~~**Sub-Annual Resource Constraint:**~~ ~~"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct The sunset date is contained within the affected language.
20.	Tariff, Definitions R-S	**Sub-Annual Resource Reliability Target**: "Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017	~~**Sub-Annual Resource Reliability Target**:~~ ~~"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or	~~Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that~~	

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].	~~produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].~~	
21.	Tariff, Definitions T-U-V	**Updated VRR Curve:** "Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction.	**Updated VRR Curve:** "Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction~~, and for Delivery Years through May 31, 2018, the Short-term Resource Procurement Target applicable to the relevant Incremental Auction~~.	Short-term Resource Procurement Target term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.
22.	Tariff, Definitions T-U-V	**Updated VRR Curve Decrement:** "Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as	**Updated VRR Curve Decrement:** "Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with ~~the transition provision of Tariff, Attachment DD,~~	Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14D, and 5.14E no longer exist in the tariff. *See PJM Interconnection, L.L.C.*, Commission Delegated Letter Order, Docket

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9	~~section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E, and~~ Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9	Nos. ER23-1265-000 *et al.* (June 6, 2023).
23.	Tariff, Definitions T-U-V	**Updated VRR Curve Increment:** "Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E and Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9	**Updated VRR Curve Increment:** "Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with ~~the transition provision of Tariff, Attachment DD, section 5.14C, Tariff, Attachment DD, section 5.14D (as related to the 2016/2017 Delivery Year), Tariff, Attachment DD, section 5.14E and~~ Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9	Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14D, and 5.14E no longer exist in the tariff. *See PJM Interconnection, L.L.C.*, Commission Delegated Letter Order, Docket Nos. ER23-1265-000 *et al.* (June 6, 2023).
24.	Tariff, Att. K Appendix, Section 6.6 (b) (ii) and (c) Operating Agreement, Schedule 1, Section 6.6 (b) (ii) and (c)	(ii) For Base Capacity Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency during hot weather operations during the period of June 1 through September 30; (ii) issues a Maximum Generation Emergency Alert or Hot Weather Alert during hot weather operations during the period of June 1 through September 30; or (iii) schedules units based on the anticipation of a Hot Weather Alert, or a Maximum Generation Emergency or Maximum Generation Emergency Alert during hot weather operations during the period of June 1 through September 30, for all, or any part, of an Operating Day.	~~(ii) For Base Capacity Resources, the Office of the Interconnection: (i) declares a Maximum Generation Emergency during hot weather operations during the period of June 1 through September 30; (ii) issues a Maximum Generation Emergency Alert or Hot Weather Alert during hot weather operations during the period of June 1 through September 30; or (iii) schedules units based on the anticipation of a Hot Weather Alert, or a Maximum Generation Emergency or Maximum Generation Emergency Alert during hot weather operations during the period of June 1 through September 30, for all, or any part, of an Operating Day.~~	Base Capacity Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A (d).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		(c) For the 2014/2015 through 2017/2018 Delivery Years for Generation Capacity Resources other than Capacity Performance Resources, and the 2016/2017 through 2018/2019 Delivery Years for Generation Capacity Resources identified and committed in an FRR Capacity Plan, parameter limited schedules shall be defined for the following parameters: (i) Turn Down Ratio; (ii) Minimum Down Time; (iii) Minimum Run Time; (iv) Maximum Daily Starts; (v) Maximum Weekly Starts. For the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, and for the 2016/2017 Delivery Year and subsequent Delivery Years for Capacity Performance Resources, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual unit on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters: (i) Turn Down Ratio; (ii) Minimum Down Time; (iii) Minimum Run Time; (iv) Maximum Daily Starts; (v) Maximum Weekly Starts; (vi) Maximum Run Time; (vii) Start-up Time; and (viii) Notification Time.	~~(c) For the 2014/2015 through 2017/2018 Delivery Years for Generation Capacity Resources other than Capacity Performance Resources, and the 2016/2017 through 2018/2019 Delivery Years for Generation Capacity Resources identified and committed in an FRR Capacity Plan, parameter limited schedules shall be defined for the following parameters: (i) Turn Down Ratio; (ii) Minimum Down Time; (iii) Minimum Run Time; (iv) Maximum Daily Starts; (v) Maximum Weekly Starts.~~ ~~For the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, and for the 2016/2017 Delivery Year and subsequent Delivery Years f~~For Capacity Performance Resources, the Office of the Interconnection shall determine the unit-specific achievable operating parameters for each individual unit on the basis of its operating design characteristics and other constraints, recognizing that remedial and ongoing investment and maintenance may be required to perform on the basis of those characteristics, for the following parameters: (i) Turn Down Ratio; (ii) Minimum Down Time; (iii) Minimum Run Time; (iv) Maximum Daily Starts; (v) Maximum Weekly Starts; (vi) Maximum Run Time; (vii) Start-up Time; and (viii) Notification Time.	
25.	Tariff, Att. K Appendix, Section 6.6, (e)-(g)	(e) For the 2014/2015 through 2017/2018 Delivery Years, upon receipt of proposed revised parameter limited schedule values from the Market Monitoring Unit, prepared in accordance with the procedures for periodic review included in Tariff, Attachment M-Appendix, section II.B.1, the Office of the Interconnection shall file to revise the Parameter Limited	~~(e) For the 2014/2015 through 2017/2018 Delivery Years, upon receipt of proposed revised parameter limited schedule values from the Market Monitoring Unit, prepared in accordance with the procedures for periodic review included in Tariff, Attachment M-Appendix, section II.B.1, the Office of the Interconnection shall file~~	Provisions in sections (e) and (f) have sunset dates that have expired. The sunset date is

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
	Operating Agreement, Schedule 1, Section 6.6, (e)-(g)	Schedule Matrix in section 6.6(d) above accordingly. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file the values that it determines are appropriate. (f) For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall calculate and provide to Market Sellers default values in accordance with Tariff, Attachment M-Appendix, section II.B. The default values set forth in the table in subsection (d) above shall apply for the referenced technology types unless a generating unit is operating pursuant to an exception from the default values under subsection (i) due to physical operational limitations that prevent the unit from meeting the minimum parameters, or any megawatts of the unit are committed as a Capacity Performance Resource in which case the unit-specific or adjusted unit-specific values for the generating unit determined by the Office of the Interconnection shall apply to all megawatts of the generating unit offered into the PJM energy markets. For generating units having the ability to operate on multiple fuels, Market Sellers may submit a parameter limited schedule associated with each fuel type. (g) For the 2016/2017 Delivery Year and subsequent Delivery Years, the following additional parameter limits shall apply for Capacity Performance Resources, other than Capacity Storage Resources, submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Capacity Performance Resource, and the	~~to revise the Parameter Limited Schedule Matrix in section 6.6(d) above accordingly. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file the values that it determines are appropriate.~~ ~~(f) For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall calculate and provide to Market Sellers default values in accordance with Tariff, Attachment M-Appendix, section II.B. The default values set forth in the table in subsection (d) above shall apply for the referenced technology types unless a generating unit is operating pursuant to an exception from the default values under subsection (i) due to physical operational limitations that prevent the unit from meeting the minimum parameters, or any megawatts of the unit are committed as a Capacity Performance Resource in which case the unit-specific or adjusted unit-specific values for the generating unit determined by the Office of the Interconnection shall apply to all megawatts of the generating unit offered into the PJM energy markets. For generating units having the ability to operate on multiple fuels, Market Sellers may submit a parameter limited schedule associated with each fuel type.~~ (g) ~~For the 2016/2017 Delivery Year and subsequent Delivery Years, t~~The following additional parameter limits shall apply for Capacity Performance Resources, other than Capacity Storage Resources, submitted in the Day-ahead Energy Market or rebidding	contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above: (i) The combined start-up and notification times shall not exceed 24 hours, except when a Hot Weather Alert or Cold Weather Alert has been issued; (ii) When a Hot Weather Alert or Cold Weather Alert has been issued, combined start-up and notification times shall not exceed 14 hours; (iii) When a Hot Weather Alert or Cold Weather Alert has been issued, notification time shall not exceed one hour; and, (iv) When a Hot Weather Alert or Cold Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Capacity Performance Resource for both its market-based schedules and cost-based schedules.	period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Capacity Performance Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above: (i) The combined start-up and notification times shall not exceed 24 hours, except when a Hot Weather Alert or Cold Weather Alert has been issued; (ii) When a Hot Weather Alert or Cold Weather Alert has been issued, combined start-up and notification times shall not exceed 14 hours; (iii) When a Hot Weather Alert or Cold Weather Alert has been issued, notification time shall not exceed one hour; and, (iv) When a Hot Weather Alert or Cold Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Capacity Performance Resource for both its market-based schedules and cost-based schedules.	
26.	Tariff, Att. K Appendix, Section 6.6 (h) Operating Agreement, Schedule 1, Section 6.6 (h)	(h) For the 2018/2019 and 2019/2020 Delivery Years, the following additional parameter limits for Base Capacity Resources submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Base Capacity Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above: (i) Combined start-up and notification times shall not exceed 48 hours;	~~(h) For the 2018/2019 and 2019/2020 Delivery Years, the following additional parameter limits for Base Capacity Resources submitted in the Day-ahead Energy Market or rebidding period that occurs after the clearing of the Day-ahead Energy Market for the following Operating Day, and for the Real-time Energy Market for the same Operating Day, unless the Capacity Market Seller has requested for its Base Capacity Resource, and the Office of the Interconnection has granted, an adjusted unit-specific start-up and/or notification time due to actual operating constraints pursuant to the process described in subsection (c) above:~~	Base Capacity Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		(ii) When a Hot Weather Alert has been issued, notification time shall not exceed one hour; and, (iii) When a Hot Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Base Capacity Resource for both its market-based schedules and cost-based schedules.	~~(i) Combined start-up and notification times shall not exceed 48 hours;~~ ~~(ii) When a Hot Weather Alert has been issued, notification time shall not exceed one hour; and,~~ ~~(iii) When a Hot Weather Alert has been issued, parameters shall be based on the actual operational limitations of the Base Capacity Resource for both its market-based schedules and cost-based schedules.~~	
27.	Tariff, Att. K Appendix, Section 6.6 (i) (ii) (1)-(5) Operating Agreement, Schedule 1, Section 6.6 (i) (ii) (1)-(5)	(1) for generating units for which no megawatts of the unit are commited as Capacity Performance Resources the default values specified in the Parameter Limited Schedule Matrix shall apply for the 2016/2017 through 2017/2018 Delivery years, (2) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which no adjusted unit-specific values have been approved by PJM, the Base Capacity Resource unit-specific values determined by PJM shall apply for the 2018/2019 and 2019/2020 Delivery Years, (3) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply for the 2016/2017 Delivery Year and subsequent Delivery Years, (4) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which adjusted unit-specific values have been approved by PJM, the Base Capacity Resource adjusted	~~(1) for generating units for which no megawatts of the unit are commited as Capacity Performance Resources the default values specified in the Parameter Limited Schedule Matrix shall apply for the 2016/2017 through 2017/2018 Delivery years,~~ ~~(2) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which no adjusted unit-specific values have been approved by PJM, the Base Capacity Resource unit-specific values determined by PJM shall apply for the 2018/2019 and 2019/2020 Delivery Years,~~ ~~(3)~~ (1) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource, but for which no adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource unit-specific values determined by PJM shall apply ~~for the 2016/2017 Delivery Year and subsequent Delivery Years~~, ~~(4) for generating units for which any megawatts of the unit are committed as a Base Capacity Resource and no megawatts are committed as a Capacity Performance Resource, and for which~~	Base Capacity Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		unit-specific values shall apply for the 2018/2019 and 2019/2020 Delivery Years, and (5) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource and for which adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource adjusted unit-specific values shall apply for the 2016/2017 Delivery Year and subsequent Delivery Years.	~~adjusted unit-specific values have been approved by PJM, the Base Capacity Resource adjusted unit-specific values shall apply for the 2018/2019 and 2019/2020 Delivery Years, and~~ ~~(5)~~ (2) for generating units for which any megawatts of the unit are committed as a Capacity Performance Resource and for which adjusted unit-specific values have been approved by PJM, the Capacity Performance Resource adjusted unit-specific values shall apply ~~for the 2016/2017 Delivery Year and subsequent Delivery Years~~.	
28.	Tariff, Att. M-Appendix, Section II.D	**D. Unit Specific Minimum Sell Offers:** 1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, sections 5.14(h) and 5.14(h-1), the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.	**D. Unit Specific Minimum Sell Offers:** 1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, section~~s 5.14(h) and~~ 5.14(h-~~1~~2), the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.	Tariff, Attachment DD, sections 5.14(h) and (h-1) have passed sunset date and are no longer relevant under the Capacity Performance construct. Section 5.14(h-2) is the relevant section under the Capacity Performance construct. *See* Row 38; Tariff, Att. DD, Sections 5.14 (h) & (h-1).
29.	Tariff, Att. Q, (4)(a) – (d)	(a) Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Auction Credit Rate shall be: (i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region	(a) Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Auction Credit Rate shall be: ~~(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry~~	Base Capacity Resource term has passed sunset date and is no longer relevant under the

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of calendar days in such Delivery Year; and (ii) For Capacity Performance Resources, the greater of ((A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in MW-day or (B) $20 per MW-day) times the number of calendar days in such Delivery Year. (iii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season. (b) Subsequent to the posting of the results from a Base Residual Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be: (i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of calendar days in such Delivery Year; and (ii) For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction	~~for the PJM Region for such Delivery Year, in MW-day or (B) $20 per MW-day) times the number of calendar days in such Delivery Year; and~~ ~~(ii)~~ (i) For Capacity Performance Resources, the greater of ((A) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in MW-day or (B) $20 per MW-day) times the number of calendar days in such Delivery Year. ~~(iii)~~ (ii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season. (b) Subsequent to the posting of the results from a Base Residual Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be: ~~(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of calendar days in such Delivery Year; and~~ ~~(ii)~~ (i) For Capacity Performance Resources, the (greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for	Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		for the Locational Deliverability Area within which the resource is located)] times the number of calendar days in such Delivery Year). (iii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season. (c) For any resource not previously committed for a Delivery Year that seeks to participate in an Incremental Auction, the Auction Credit Rate shall be: (i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located or (C) $20 per MW-day) times the number of calendar days in such Delivery Year; and (ii) For Capacity Performance Resources, the (greater of (A) 0.5 times Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA or (B) $20/MWday) times the number of calendar days in such Delivery Year. (d) Subsequent to the posting of the results of an Incremental Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be: (i) For Base Capacity Resources: (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times	such Delivery year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of calendar days in such Delivery Year). ~~(iii)~~ (ii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season. (c) For any resource not previously committed for a Delivery Year that seeks to participate in an Incremental Auction, the Auction Credit Rate shall be: ~~(i) For all Capacity Resources other than Capacity Performance Resources, (the greater of (A) 0.3 times the Net Cost of New Entry for the PJM Region for such Delivery Year, in MW-day or (B) 0.24 times the Capacity Resource Clearing Price in the Base Residual Auction for such Delivery Year for the Locational Deliverability Area within which the resource is located or (C) $20 per MW-day) times the number of calendar days in such Delivery Year; and~~ ~~(ii)~~ (i) For Capacity Performance Resources, the (greater of (A) 0.5 times Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA or (B) $20/MWday) times the number of calendar days in such Delivery Year. (d) Subsequent to the posting of the results of an Incremental Auction, the Auction Credit Rate used for ongoing credit requirements for supply committed in such auction shall be:	

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		the number of calendar days in such Delivery Year, but no greater than the Auction Credit Rate previously established for such resource's participation in such Incremental Auction pursuant to subsection (c) above) times the number of calendar days in such Delivery Year; (ii) For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of calendar days in such Delivery Year); and (iii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season.	~~(i) For Base Capacity Resources: (the greater of (A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located) times the number of calendar days in such Delivery Year, but no greater than the Auction Credit Rate previously established for such resource's participation in such Incremental Auction pursuant to subsection (c) above) times the number of calendar days in such Delivery Year; (ii)~~ (i) For Capacity Performance Resources, the greater of [(A) $20/MW-day or (B) 0.2 times the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located or (C) the lesser of (1) 0.5 times the Net Cost of New Entry for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day or (2) 1.5 times the Net Cost of New Entry (stated on an installed capacity basis) for the PJM Region for such Delivery Year or for the Relevant LDA, in $/MW-day minus (the Capacity Resource Clearing Price in such auction for the Locational Deliverability Area within which the resource is located)] times the number of calendar days in such Delivery Year); and ~~(iii)~~ (ii) For Seasonal Capacity Performance Resources, the same as the Auction Credit Rate for Capacity Performance Resources, but reduced to be proportional to the number of calendar days in the relevant season.	
30.	Tariff, Att. DD, Section 3.2 Administration of the Base	3.2 Administration of the Base Residual Auction and Incremental Auctions The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this	3.2 Administration of the Base Residual Auction and Incremental Auctions	Terms listed in (c) through (e) have passed sunset dates and are no longer relevant under

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
	Residual Auction and Incremental Auctions	Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following: a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers; b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements; c) Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017; d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for the 2017/2018 Delivery Year; e) Determining Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints for the 2018/2019 and 2019/2020 Delivery Years; f) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction	The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following: a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers; b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements; ~~c) Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017;~~ ~~d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for the 2017/2018 Delivery Year;~~ ~~e) Determining Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints for the 2018/2019 and 2019/2020 Delivery Years;~~ ~~f)~~ c) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction	the Capacity Performance construct. The sunset date is contained within the affected language.
31.	Tariff, Att. DD, 5.2 Nomination of Self Supplied Capacity Resources	**5.2 Nomination of Self Supplied Capacity Resources** A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the	**5.2 Nomination of Self Supplied Capacity Resources** A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure	Tariff, Attachment DD, section 5.14(h) and 5.14(h-2) have passed sunset date. Minimum offer price rule that is relevant is in section

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the minimum offer price rule set forth in Tariff, Attachment DD, section 5.14(h) and Tariff, Attachment DD, section 5.14(h-1). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Tariff, Attachment DD, section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.	and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the minimum offer price rule set forth in Tariff, Attachment DD, ~~section 5.14(h) and Tariff, Attachment DD,~~ section 5.14~~(h-1)~~ (h-2). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Tariff, Attachment DD, section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.	5.14 (h-2). *See* Row 38; Tariff, Att. DD, Sections 5.14 (h) & (h-1).
32.	Tariff, Att. DD, Section 5.5A (d)	(d) Base Capacity Resources For the 2018/2019 and 2019/2020 Delivery Years, following types of Capacity Resources eligible to submit a Sell Offer as a Base Capacity	~~(d) Base Capacity Resources~~ ~~For the 2018/2019 and 2019/2020 Delivery Years, following types of Capacity Resources eligible to submit a Sell Offer as a Base~~	Base Capacity Resource term has passed sunset date and is no longer relevant under the

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Resource: Generation Capacity Resources, Capacity Storage Resources, Annual Demand Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Each resource that clears a RPM Auction as a Base Capacity Resource must provide energy output to PJM if called during Performance Assessment Intervals occurring in the calendar months of June through September, including any necessary recall of such capacity and energy from service to areas outside the PJM Region. As further detailed in Tariff, Attachment DD, section 10A, Base Capacity Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d).	~~Capacity Resource: Generation Capacity Resources, Capacity Storage Resources, Annual Demand Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Each resource that clears a RPM Auction as a Base Capacity Resource must provide energy output to PJM if called during Performance Assessment Intervals occurring in the calendar months of June through September, including any necessary recall of such capacity and energy from service to areas outside the PJM Region. As further detailed in Tariff, Attachment DD, section 10A, Base Capacity Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Tariff, Attachment DD, section 10A(d).~~	Capacity Performance construct. The sunset date is contained within the affected language.
33.	Tariff, Att. DD, Section 5.7 (c)	5.7 Buy Bids Buy Bids may be submitted in any Incremental Auction. Buy Bids shall specify, as appropriate: …. c) The type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource; and	5.7 Buy Bids Buy Bids may be submitted in any Incremental Auction. Buy Bids shall specify, as appropriate: … c) The type of Unforced Capacity desired, i.e., Annual Resource, ~~Extended Summer Demand Resource, or Limited Demand Resource;~~ and	Terms listed have passed sunset date and are no longer relevant under the Capacity Performance construct. *See* Rows 55 and 56; RAA, Article 1 – Definitions.
34.	Tariff, Att. DD, Section 5.8 (c)	c) A Buy Bid that fails to designate the type of Unforced Capacity desired, i.e., an Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource, shall be rejected by the Office of the Interconnection.	c) A Buy Bid that fails to designate the type of Unforced Capacity desired, i.e., an Annual Resource, ~~Extended Summer Demand Resource, or Limited Demand Resource,~~ shall be rejected by the Office of the Interconnection.	Terms listed have passed sunset date and are no longer relevant under the Capacity Performance construct. *See* Rows 55 and 56;

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
				RAA, Article 1 – Definitions.
35.	Tariff, Att. DD, Section 5.6.1 (g)	(g) A Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods, not to exceed the Accredited UCAP of such resource, as applicable. Alternatively, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its Capacity Exchange tools. If any of the commercially aggregated resources in such Sell Offer are subject to the Minimum Floor Offer Price pursuant to Tariff, Attachment DD, section 5.14 (h-2), the Capacity Market Seller that owns or controls such resources may submit a Sell Offer with a Minimum Floor Offer Price of no lower than the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer.	(g) A Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods, not to exceed the Accredited UCAP of such resource, as applicable. Alternatively, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its Capacity Exchange tools. If any of the commercially aggregated resources in such Sell Offer are subject to the Minimum Floor Offer Price pursuant to Tariff, Attachment DD, section-5.14-(h-2), the Capacity Market Seller that owns or controls such resources may submit a Sell Offer with a Minimum Floor Offer Price of no lower than the time and MW-weighted average of the applicable MOPR	Tariff, Section 5.14(h) and (h-1) have passed sunset dates and are no longer relevant under the Capacity Performance construct. Minimum Offer Price rule in Tariff, Section 5.14(h-2) is the relevant section under the Capacity Performance construct. *See* Row 38; Tariff, Att. DD, Sections 5.14 (h) & (h-1).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
			Floor Offer Prices (zero if not applicable) of the aggregated resources in such Sell Offer.	
36.	Tariff, Att. DD, Section 5.11 (a) (vi)	vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year , the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;	~~vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year , the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year;~~	Terms listed have passed sunset date and are no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.
37.	OATT, Att. DD, Section 5.14, (c), (3)	3.Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which	3.Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement~~, minus the Short Term Resource Procurement Target,~~ to a megawatt quantity at or above a megawatt quantity at the price-	Short Term Resource Procurement Target term has passed its sunset date and is no longer relevant under the Capacity Performance construct.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd) through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.	quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd) through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.	*See* Tariff, Article 1, Definitions R-S ("'Short-Term Resource Procurement Target' shall mean, for Delivery Years through May 31, 2018…")
38.	OATT, Att. DD, Sections 5.14 (h) & (h-1)	OATT, Att DD, Sections 5.14(h) & (h-1) https://agreements.pjm.com/oatt/5156	Delete the entirety of Sections 5.14(h) & (h-1) https://agreements.pjm.com/oatt/5156	Sections 5.14(h) & (h-1) have passed sunset dates and are no longer relevant under Capacity Performance construct. The sunset date is contained within the affected language.
39	OATT, Att. DD, Section 5.14 (f) (iii)	iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.	iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction, First Incremental, or ~~and~~ Second Incremental Auction.	Requests for relief from Capacity Resource Deficiency Charges for DR Resources due to permanent departure of load (OATT Att. DD, Section 8.4) are not limited Base Residual Auction and Second Incremental Auction commitments. Final Zonal Capacity Prices

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
				must be adjusted to account for approved requests for relief from Base Residual Auction, First Incremental, or Second Incremental Auction commitments to ensure that total RPM charges equal RPM credits.
40.	Tariff, Att. DD, Section 6.7 (c)	To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.	~~To determine the default retirement and mothball ACR values for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the Office of the Interconnection shall multiply the updated base default retirement and mothball ACR values from the immediately preceding Delivery Year by a factor equal to one plus the most recent annual average rate of change in the July Handy-Whitman Index. These values become the new adjusted base default retirement and mothball ACR values, as calculated by the Office of the Interconnection and posted to its website. These resulting adjusted base values for the Delivery Year shall be multiplied by a factor equal to one plus the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index, taken to the fourth power, as calculated by the Office of the Interconnection and posted to its website.~~	Base Capacity Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
41.	Tariff, Att. DD, Section 6.8	**CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of nonperformance associated with submission of a Capacity Performance	**CPQR (Capacity Performance Quantifiable Risk)** consists of the quantifiable and reasonably-supported costs of mitigating the risks of nonperformance associated with submission of a Capacity	Base Capacity Resource term has passed sunset date and is no longer

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Resource offer (or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years), such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.	Performance Resource offer ~~(or of a Base Capacity Resource offer for the 2018/19 or 2019/20 Delivery Years)~~, such as insurance expenses associated with resource non-performance risks. CPQR shall be considered reasonably supported if it is based on actuarial practices generally used by the industry to model or value risk and if it is based on actuarial practices used by the Capacity Market Seller to model or value risk in other aspects of the Capacity Market Seller's business. Such reasonable support shall also include an officer certification that the modeling and valuation of the CPQR was developed in accord with such practices. Provision of such reasonable support shall be sufficient to establish the CPQR. A Capacity Market Seller may use other methods or forms of support for its proposed CPQR that shows the CPQR is limited to risks the seller faces from committing a Capacity Resource hereunder, that quantifies the costs of mitigating such risks, and that includes supporting documentation (which may include an officer certification) for the identification of such risks and quantification of such costs. Such showing shall establish the proposed CPQR upon acceptance by the Office of the Interconnection.	relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
42.	Tariff, Att. DD, Section 8.1	A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability	A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational	Terms listed have passed sunset date and are no longer relevant to the Capacity Performance construct. *See* Rows 55 and 56; RAA, Article 1 – Definitions.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		characteristics (i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:	requirements and same or better temporal availability characteristics (i.e., Annual Resource, ~~Extended Summer Demand Resource, or Limited Demand Resource~~) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:	
43.	OATT, Att. DD, Section 10A, (c)	Such calculation shall encompass all resources and Price Responsive Demand located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying	Such calculation shall encompass all resources and Price Responsive Demand located in the area defined by the Emergency Action; provided, however, that Performance Shortfall shall be calculated for external Generation Capacity Resources for any Performance Assessment Interval for which performance by such external resource would have helped resolve the declared Emergency Action that was the subject to the Performance Assessment Hour; provided, however, that for any Delivery Year up to and including the 2019/2020 Delivery Year, Performance Shortfall shall be calculated for external Generation Capacity Resources only during Performance Assessment Hours which the Emergency Action was declared for the entire PJM Region. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned. For purposes of this provision, Qualifying Transmission Upgrades shall be deemed to be located in the Locational	Base Capacity Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval. For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Interval shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.	Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit, and a Qualifying Transmission Upgrade shall be included in calculations of Expected Performance and Actual Performance only if, and to the extent that, the declared Emergency Action encompasses the Locational Deliverability Area into which such upgrade increased the Capacity Emergency Transfer Limit. The Performance Shortfall shall be calculated for each Performance Assessment Interval, and any committed Capacity Resource for which the above calculation produces a negative number for a Performance Assessment Interval shall not have a Performance Shortfall for such Performance Assessment Interval. ~~For any resource that is partially committed as a Capacity Performance Resource and partially committed as a Base Capacity Resource, the performance of such resource during a Performance Assessment Interval shall first be attributed to the resource's Capacity Performance Resource obligation; any performance by such resource in excess of the Capacity Performance Resource's Expected Performance shall be attributed to the resource's Base Capacity Resource obligation.~~	
44.	Tariff, Att. DD, Section 10A, (e)	(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:	(e) Subject to the Non-Performance Charge Limit specified in subsection (f) hereof, each Capacity Market Seller and Locational UCAP Seller shall be assessed a Non-Performance Charge for each of its Capacity Resources or Locational UCAP that has a Performance Shortfall for a Performance Assessment Interval based on the following formula, applied to each such resource:	Base Capacity Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate Where For Capacity Performance Resources and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour). and for Base Capacity Resources the Non-Performance Charge Rate = (Weighted Average Resource Clearing Price applicable to the resource * (the number of days in the Delivery Year / 30) (the number of Real-Time Settlement Intervals in an hour)	Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate Where For Capacity Performance Resources and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour). ~~and for Base Capacity Resources the Non-Performance Charge Rate = (Weighted Average Resource Clearing Price applicable to the resource * (the number of days in the Delivery Year / 30) (the number of Real-Time Settlement Intervals in an hour)~~	
45.	Tariff, Att. DD, Section 10A, (f)	(f) The Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource or such PRD Provider times the number of days in the Delivery Year. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. The total Non-Performance Charges for each Base Capacity Resource (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a NonPerformance Charge Limit equal to the total payments due such Capacity Resource or Locational UCAP under Tariff, Attachment DD, section 5.14 for such Delivery Year. The NonPerformance Charges for each Seasonal Capacity Performance Resource for a Delivery	(f) The Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource or such PRD Provider times the number of days in the Delivery Year. All references to Net Cost of New Entry in this section 10A shall be to the Net Cost of New Entry for the LDA and Delivery Year for which the calculation is performed. ~~The total Non-Performance Charges for each Base Capacity Resource (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a NonPerformance Charge Limit equal to the total payments due such Capacity Resource or Locational UCAP under Tariff, Attachment DD, section 5.14 for such Delivery Year.~~ The	Base Capacity Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.	NonPerformance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the season applicable to such resource.	
46.	Tariff, Att. DD, Section 10A, (f-1)	(f-1)Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource or such PRD Provider, where such megawatts shall be based on the maximum Unforced Capacity committed up through the end of the month in which the PAI occurs, times the number of days in the Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource, where such megawatts shall be based on maximum Unforced Capacity committed up through the end of the month in which the Performance Assessment Interval occurs, times the number of days in the season applicable to such resource.	(f-1)Effective with the 2025/2026 Delivery Year and subsequent Delivery Years, the Non-Performance Charges for each Capacity Performance Resource (including Locational UCAP from such a resource) and each PRD Provider for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price ~~times the number of days in the Delivery Year~~ for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource or such PRD Provider, where such megawatts shall be based on the maximum Unforced Capacity committed up through the end of the month in which the PAI occurs, times the number of days in the Delivery Year. The Non-Performance Charges for each Seasonal Capacity Performance Resource for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the RPM Base Residual Auction clearing price times the number of days in the Delivery Year for the applicable Delivery Year and for the LDA where the resource resides, times the megawatts of Unforced Capacity committed by such resource, where such megawatts shall be based on maximum Unforced Capacity committed up through the end of the month in which the Performance Assessment	Non-Performance Charge Limit calculation incorrectly states "times the number of days in the Delivery Year" twice due to a drafting error. *See PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 at P 210.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
			Interval occurs, times the number of days in the season applicable to such resource.	
47.	Tariff, Att. DD, Section 10A, (g)	Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the resource's capacity obligation period, including, without limitation, a Base Capacity Demand Resource providing demand response during non-summer months; and	Expected Performance is as defined in subsection (c), provided, however, that for purposes of this calculation, Expected Performance shall be zero for any resource that is not a Capacity Resource or Locational UCAP, or that is a Capacity Resource or Locational UCAP, but for which the Performance Assessment Interval occurs outside the resource's capacity obligation period~~, including, without limitation, a Base Capacity Demand Resource providing demand response during non-summer months~~; and	Base Capacity Demand Resource term has passed sunset date and is no longer relevant in the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
48.	Tariff, Att. DD, Section 11 Demand Resource Compliance Penalty Charge	**Section 11 Demand Resource Compliance Penalty Charge (https://agreements.pjm.com/oatt/5164)**	Delete the entirety of Section 11 Demand Resource Compliance Penalty Charge **(https://agreements.pjm.com/oatt/5164)**	Provisions of Section 11 are not applicable to Demand Resources committed as Capacity Performance Resources. *See* Tariff, Attachment DD, section 11(a) (limiting the applicability of this section through May 31, 2019).
49.	RAA, Article 1 - Definitions	**Base Capacity Demand Resource:** "Base Capacity Demand Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through	~~**Base Capacity Demand Resource:**~~ ~~"Base Capacity Demand Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.	~~available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.~~	date is contained within the affected language.
50.	RAA, Article 1 – Definitions	**Base Capacity Energy Efficiency Resource:** "Base Capacity Energy Efficiency Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.	~~**Base Capacity Energy Efficiency Resource:**~~ ~~"Base Capacity Energy Efficiency Resource" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
51.	RAA, Article 1 – Definitions	**Base Capacity Resource:** "Base Capacity Resource" shall have the same meaning as in Tariff, Attachment DD.	~~**Base Capacity Resource:**~~ ~~"Base Capacity Resource" shall have the same meaning as in Tariff, Attachment DD.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
52.	RAA, Article 1 - Definitions	**Demand Resource (DR):** "Demand Resource" or "DR" shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.	**Demand Resource (DR):** "Demand Resource" or "DR" shall mean an ~~Limited Demand Resource, Extended Summer Demand Resource,~~ Annual Demand Resource, ~~Base Capacity Demand Resource~~ or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.	Limited Demand Resource, Extended Summer Demand Resource, and Base Capacity Demand Resource terms have passed sunset date and are no longer relevant under the Capacity Performance construct. *See* Rows 49, 55, and 56; RAA, Article 1 – Definitions.
53.	RAA, Article 1 – Definitions	**Demand Resource Factor or DR Factor:** "Demand Resource Factor" or "DR Factor" shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6	~~**Demand Resource Factor or DR Factor:**~~ ~~"Demand Resource Factor" or "DR Factor" shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
54.	RAA, Article 1 - Definitions	**Energy Efficiency Resource:** "Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.	**Energy Efficiency Resource:** "Energy Efficiency Resource" shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources~~, Base Capacity Energy Efficiency Resources~~ and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.	Base Capacity Energy Efficiency Resource term has passed sunset date and is no longer relevant under the Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
55.	RAA, Article 1 - Definitions	**Extended Summer Demand Resource:** "Extended Summer Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited	~~**Extended Summer Demand Resource:**~~ ~~"Extended Summer Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.	~~available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.~~	
56.	RAA, Article 1 - Definitions	**Limited Demand Resource:** "Limited Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.	~~**Limited Demand Resource:**~~ ~~"Limited Demand Resource" shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.~~	Term has passed sunset date and is no longer relevant under the Capacity Performance construct. The sunset date is contained within the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
57.	RAA, Article 1 - Definitions	**Peak Shaving Adjustment:** "Peak Shaving Adjustment" shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Base Capacity Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.	**Peak Shaving Adjustment:** "Peak Shaving Adjustment" shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, ~~Base Capacity Demand Resource,~~ Capacity Performance Demand Resource, or Economic Load Response Participant.	Base Capacity Demand Resource term has passed sunset date and is no longer relevant under the Capacity Performance Construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
58.	Tariff, Attachment DD-1, Section K RAA, Schedule 6, Section K	Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a Base or Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.	Load reduction compliance is determined on an hourly basis for a Demand Resource Registration linked to an Annual Demand Resource with a Capacity Performance commitment, for each FSL and GLD customer dispatched by the Office of the Interconnection for at least 30 minutes of the clock hour (i.e., "partial dispatch compliance hour"). Curtailment Service Provider may submit 1 minute load data for use in capacity compliance calculations for partial dispatch compliance hours subject to PJM approval and in accordance with the PJM Manuals where: (a) metering meets all Tariff and Manual requirements, (b) 1 minute load data shall be submitted to PJM for all locations on the registration, and (c) 1 minute load data measures energy consumption over the minute. The registered capacity commitment for a Demand Resource Registration with a ~~Base or~~ Capacity Performance commitment is not prorated based on the number of minutes dispatched during the clock hours. The actual hourly load reduction for the hour ending that includes a Performance	Base commitment is no longer relevant since Base Capacity Resource term has passed its sunset date. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
			Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour in accordance with the PJM Manuals.	
59.	RAA, Schedule 8.1 C (1)	1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. No later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources, Seasonal Capacity Performance Resources, and Base Capacity Resources, as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.	1. No less than four months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan. No later than the last business day prior to the start of the relevant Delivery Year in which Capacity Performance requirements shall apply to such FRR Entity, the FRR Entity must also elect whether it seeks to be subject to the Non-Performance Charge for Capacity Performance Resources~~,~~ and Seasonal Capacity Performance Resources, ~~and Base Capacity Resources~~, as provided in section 10A of Attachment DD of the PJM Tariff, and described in section G.1 of this Schedule 8.1, or to physical non-performance assessments, as described in section G.2 of this Schedule 8.1.	Base Capacity Resource term has passed sunset date and is no longer relevant under Capacity Performance construct. *See* Row 32; Tariff, Att. DD, Section 5.5A(d).
60.	RAA, Schedule 8.1.G (1)	Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, Tariff, Attachment	Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment	ER24-98 filing was not approved by FERC. The physical Non-Performance

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, however, through the 2024/2025 Delivery Year, only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.	DD, section 10A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, ~~however, through the 2024/2025 Delivery Year,~~ only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.	Assessment option for FRR Entities still remains in effect. The sunset date is contained within the affected language.
61.	RAA, Schedule 8.1, section H, (3), (a)	3. Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR Entity: a. For any Delivery Year for which a Base Residual Auction already has been conducted, PJM would consider shifted load as unanticipated load	3. Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR Entity: a. For any Delivery Year for which a Base Residual Auction already has been conducted, PJM would consider shifted load as	Terms listed in this section have passed sunset date and are no longer relevant in the Capacity Performance

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		growth for purposes of determining the RTO/LDA Reliability Requirements, Limited Resource and Sub-Annual Constraints for the 2017/2018 Delivery Year, and Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint for the 2018/2019 and 2019/2020 Delivery Years in all future Incremental Auctions for such Delivery Years, and such shifted load shall pay a Locational Reliability Charge. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.	unanticipated load growth for purposes of determining the RTO/LDA Reliability Requirements, ~~Limited Resource and Sub-Annual Constraints for the 2017/2018 Delivery Year, and Base Capacity Demand Resource Constraint and Base Capacity Resource Constraint for the 2018/2019 and 2019/2020 Delivery Years in all future Incremental Auctions for such Delivery Years,~~ and such shifted load shall pay a Locational Reliability Charge. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.	construct. The sunset date is contained within the affected language.
62.	Tariff, Attachment K-Appendix, section 3.2.3(f-5)(i)-(v) Operating Agreement, Schedule 1, section 3.2.3(f-5)(i)-(v).	(f-5) If a Market Participant of an Energy Storage Resource Model Participant believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. Following such discussion, if the Office of the Interconnection	(f-5) If a Market Participant of an Energy Storage Resource Model Participant believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. Following such discussion, if the Office of the Interconnection accepts a	Two different, unrelated (f-5)s were proposed in overlapping filings. PJM proposes separating the provisions relating to pool-scheduled and dispatchable self-scheduled resources that was filed on August 30,

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of 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) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section (f-4). (iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-5)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-5)(iii) or (B) zero.	modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of 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-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section (f-4). (iv)The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-6~~5~~)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-6~~5~~)(iii) or (B) zero.	2019 in Docket No. ER19-2722 as section 3.2.3(f-5)(i)-(v) from the provisions in section 3.2.3(f-5) referencing Energy Storage Resources filed on April 30, 2021, in Docket No. ER21-1802-000.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
63.	Tariff, Schedule 6A, section 18	"X" is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For non-fuel assured Black Start Units with a commitment established under section 5 of this Schedule 6A, X shall be .01 for Hydro units, .02 for CT units. For fuel assured Black Start Units with a commitment established under section 5 of this Schedule 6A, X shall be .02 for all units.	"X" is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For non-fuel assured Black Start Units with a commitment established under ~~section 5 of this~~ Schedule 6A, X shall be .01 for Hydro units, .02 for CT units. For fuel assured Black Start Units with a commitment established under ~~section 5 of this~~ Schedule 6A, X shall be .02 for all units.	This change removes the reference to "section 5" to make it clear that the value of "X" in the formula rate applies to both the Base Formula Rate under Section 5, and the NERC-CIP Recovery rate. The filings in Docket No. ER11-4402-000, where PJM added the Schedule 6A NERC-CIP Recovery rate provisions in section 18 supports this change because the NERC-CIP Recovery X factor was always intended to be the same value as the X factor applicable to the Based Formula Rate with a commitment period established under Section 5. The failure to delete the limiting references to "under

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
				section 5" in the definition of the "X" factor in section 18 at the time PJM filed to add the Schedule 6A NERC-CIP Recovery rate provisions in section 18 was an oversight because the intent was always to use the same value for "X" in the Schedule 6A formula rates. The FERC order accepting PJM's August 30, 2011 filing to amend Schedule 6A, specifically stated as follows: "This proposed formulaic calculation is, essentially, the Base Formula Rate with the added ability to document, and recover, incremental NERC-CIP

<table>
<tr><th></th><th>Governing Document, Agreement, Attachment, Section, Title</th><th>Current Language</th><th>Proposed Revisions</th><th>Rationale/Notes</th></tr>
<tr><td></td><td></td><td></td><td></td><td>specific capital costs (at P8).”</td></tr>
<tr><td>64.</td><td>Tariff, Schedule 6A, section 18</td><td>The CRF applicable to Black Start Capital Costs and/or for Fuel Assurance Capital Costs, of Black Start Units selected for Black Start Service after June 6, 2021, shall be updated annually on March 1 for (i) federal income tax rates as utilized by the U.S. Internal Revenue Service in effect at the time of the annual CRF update; (ii) average state tax rate; and (iii) debt interest rates and shall be posted on the PJM website by March 31 each year as shown in the table below. Interested parties shall have until April 15 of each year to contest PJM’s calculation of the annual CRF value before it becomes effective on June 1 of each year.
<table>
<tr><td>PJM determines annual CRF inputs</td><td>March 1</td></tr>
<tr><td>PJM posts annual CRF</td><td>March 31</td></tr>
<tr><td>Deadline for contesting annual CRF</td><td>April 15</td></tr>
<tr><td>Annual revenue requirement calculation</td><td>May 3 through May 27</td></tr>
<tr><td>Annual revenue requirement with CRF in effect</td><td>June 1</td></tr>
</table></td><td>The CRF applicable to Black Start Capital Costs and/or for Fuel Assurance Capital Costs, of Black Start Units selected for Black Start Service after June 6, 2021, shall be updated annually on March 1 (if March 1 is not a Business day then the first Business Day after March 1) for (i) federal income tax rates as utilized by the U.S. Internal Revenue Service in effect at the time of the annual CRF update; (ii) average state tax rate; and (iii) debt interest rates and shall be posted on the PJM website by March 31 each year as shown in the table below. Interested parties shall have until April 15 of each year to contest PJM’s calculation of the annual CRF value before it becomes effective on June 1 of each year.
<table>
<tr><td>PJM determines annual CRF inputs</td><td>March 1 (if March 1 is not a Business day then the first Business Day after March 1)</td></tr>
<tr><td>PJM posts annual CRF</td><td>March 31</td></tr>
<tr><td>Deadline for contesting annual CRF</td><td>April 15</td></tr>
<tr><td>Annual revenue requirement calculation</td><td>May 3 through May 27</td></tr>
<tr><td>Annual revenue requirement with CRF in effect</td><td>June 1</td></tr>
</table></td><td>Corrections to Tariff, Schedule 6A, section 10, to clarify that annual CRF updates will occur on March 1 or the first Business Day after March 1, and the inputs to perform the annual CRF calculations will be as of March 1 or the first Business Day after March 1. These non-substantive Tariff changes are needed to address inaccurate Tariff provisions by conforming the annual CRF update and calculation procedures with necessary and established business practices.</td></tr>
</table>

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
65.	Tariff, Definitions C-D	**Demand Resource:** "Demand Resource" shall mean a resource with the capability to provide a reduction in demand.	~~**Demand Resource:**~~ ~~"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.~~	This term is outdated, as that term was replaced to the updated definition in RAA, Article 1, Definitions. *See PJM Interconnection, L.L.C.*, Capacity Performance Filing, Docket No. ER15-623-000 at 35 (Dec. 12, 2014) ("PJM is proposing to transition from the current three Demand Resource products to a single Annual Demand Resource product that will meet the Capacity Performance Resource operational and performance requirements by the 2020/2021 Delivery Year"); *see also PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 99 (2015).

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
66.	Tariff, Definitions R-S	**Short-Term Resource Procurement Target:** "Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.	~~**Short-Term Resource Procurement Target:**~~ ~~"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.~~	This definition has sunset. The sunset date for this definition is contained in the affected language.
67.	Tariff, Definitions R-S	**Short-Term Resource Procurement Target Applicable Share:** "Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual	~~**Short-Term Resource Procurement Target Applicable Share:**~~ ~~"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term~~	This definition has sunset. The sunset date for this definition is contained in the affected language.

	Governing Document, Agreement, Attachment, Section, Title	Current Language	Proposed Revisions	Rationale/Notes
		Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.	~~Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.~~	