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June 1, 2018

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

*Re: PJM Interconnection, L.L.C., Docket No. ER18-1730-000  
Pseudo-Tie Generator Market-to-Market Congestion—Phase II*

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act (“FPA”), 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission (“FERC” or “Commission”), PJM Interconnection, L.L.C. (“PJM”) hereby files revisions to the *PJM Open Access Transmission Tariff* (“PJM Tariff”) and the *Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.* (“Operating Agreement”) to: (1) provide market participants with a new transaction type to hedge exposure to financial risk for pseudo-ties from PJM into Midcontinent Independent System Operator, Inc. (“MISO”); and (2) charge or credit pseudo-tie transactions from MISO to the PJM-MISO interface for real-time deviations from day-ahead schedules for congestion resulting from market-to-market coordination pursuant to the Commission-approved *Joint Operating Agreement Between the Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.* (“JOA”). PJM requests an effective date of August 1, 2018, for the PJM Tariff and Operating Agreement revisions proposed herein.

## **I. BACKGROUND**

On October 23, 2017, PJM and MISO (collectively, the “RTOs”) filed revisions to the JOA to address overlapping congestion charges on pseudo-tie generation resources.<sup>1</sup> The Phase 1 Filing contains the first of two phases of JOA and tariff revisions to reduce overlapping congestion that occurs on a limited number of flowgates during market-to-market coordination. In the Phase 1 Filing, the RTOs explained that the first phase of the solution comprises the JOA revisions in the Phase 1 Filing and the second phase would require MISO and PJM to submit a future filing modifying their respective tariffs to create a mechanism that allows pseudo-tie owners to hedge transmission usage charges for congestion in the native balancing authority area and to specify other charges and credits for pseudo-tie transmission transactions. This filing sets forth the second phase of the solution and associated revisions to the PJM Tariff and Operating Agreement.

## **II. PROPOSED REVISIONS TO THE PJM TARIFF AND OPERATING AGREEMENT**

### ***A. Day-Ahead Pseudo-Tie Transactions from PJM to MISO***

PJM proposes to add a new type of transaction to the PJM Tariff and Operating Agreement that allows each market participant with a pseudo-tie generator from PJM to MISO to submit a day-ahead bid associated with a real-time physical transaction that specifies the maximum amount a market participant will pay for congestion between the source (i.e., the pseudo-tie generator) and sink of the transaction (i.e., the PJM-MISO interface) (“Day-Ahead Pseudo-Tie Transactions”). If the congestion charges are less than the amount specified in the bid, then the transaction will be scheduled in the day-ahead energy market.

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<sup>1</sup> *PJM Interconnection, L.L.C.*, Docket No. ER18-137-000 (Oct. 23, 2017) (“Phase 1 Filing”).

Among other benefits, such as those described in section II.C below, Day-Ahead Pseudo-Tie Transactions will assist market participants with generator pseudo-ties from PJM to MISO in managing uncertain congestion charges by allowing them to reflect their risk-weighted maximum exposure amount with their Day-Ahead Pseudo-Tie Transaction. Market participants with pseudo-tie generators will now be able to utilize a mechanism in the day-ahead energy market to manage the exposure to price differentials from the source (i.e., the generator within PJM) to the sink (i.e., the PJM-MISO interface) from the real-time energy market. With this new type of transaction, market participants will be able to obtain a day-ahead locational marginal obligation, which includes binding day-ahead congestion charges, up to the megawatt quantity of the transmission service associated with the transaction. Moreover, the market participant may specify the maximum difference between the locational marginal prices at the source and sink thereby allowing the market participant to limit the amount of congestion that it is willing to pay for a transaction. If the congestion charges are less than the amount specified by the market participant, then the transaction will be scheduled in the day-ahead energy market. As further described below, allowing the market participant to lock in day-ahead prices, lock in day-ahead congestion charges, and specify the maximum congestion based on the differences in the locational marginal prices between a transaction's source and sink reduces financial risk and aligns congestion costs for market participants.

***B. Credits and Charges for Deviations Between Day-Ahead and Real-Time Pseudo-Tie Transactions from MISO into PJM***

PJM also proposes to revise the PJM Tariff and Operating Agreement to charge or credit a market participant for balancing deviation congestion associated with the overlap congestion

from the market participant's pseudo-tie generator within MISO to the PJM-MISO interface.<sup>2</sup> In the Phase 1 Filing, JOA revisions allowed for properly valuing pseudo-tie congestion in the day-ahead energy market for the overlap portion from the pseudo-tie unit to the PJM-MISO interface. However, the first phase did not account for circumstances where the quantity of a transaction from the overlap portion in the day-ahead energy market was different than the actual flow in the real-time market. This second phase change will properly credit or charge the pseudo-tie owner for the difference in flow between the day-ahead and the real-time energy market associated with the overlap portion of the transaction from the generator to the PJM-MISO interface. The credit or charge will be based on the deviations of the overlap portion of the pseudo-tie path on only market-to-market constraints because it is only the market-to-market constraints on which the overlapping congestion exists. Normal balancing deviations not associated with the congestion overlap adjustment may still exist and these normal balancing deviation credits or charges will not be impacted by the proposed changes in this filing.

### ***C. Benefits of the Proposed Revisions to the PJM Tariff and Operating Agreement***

The proposed revisions in this filing will benefit both market participants with pseudo-ties and the other PJM market participants. For example, under the rules proposed in this filing, market participants with PJM-MISO pseudo-tie generators: (1) will be able to hedge against transmission congestion charges resulting from PJM-MISO market-to-market coordination; (2) will be charged or paid for unplanned real-time deviations on market-to-market flowgates during market-to-market coordination; and (3) will have more incentive to follow dispatch because market participants for such generators will be paid real-time prices for any generation that

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<sup>2</sup> Balancing deviations for a generator are deviations between the generator's day-ahead schedule and its real-time, actual generation. Generators are paid real-time balancing prices for any generation that exceeds their day-ahead scheduled amounts and pay for any generation deficit below their day-ahead scheduled amounts.

exceeds their day-ahead scheduled amounts and will pay for any generation deficit below their day-ahead scheduled amounts. Importantly, the revisions proposed herein will also result in the more comparable treatment of pseudo-tie generators into PJM with generators located in PJM by consistently charging congestion for the overlap portion of the pseudo-tie path.

***D. Description of Amendments to the PJM Tariff and Operating Agreement***

PJM proposes the following modifications to the PJM Tariff and Operating Agreement to effectuate the changes described above.

***1. New Section 1.10 (n) in the Appendix to Attachment K of the PJM Tariff and Schedule 1 of the Operating Agreement***

New section 1.10 (n) contains the rules pertaining to Day-Ahead Pseudo-Tie Transactions described above in section II.A. To ensure the appropriate users (i.e., only market participants with pseudo-tie generators physically exporting energy from PJM into MISO) are utilizing Day-Ahead Pseudo-Tie Transactions, this new transaction type will only be available for market participants with pseudo-tie generators. Moreover, each pseudo-tie owner will only be able to submit bids for Day-Ahead Pseudo-Tie Transactions from its pseudo-tie generator to the PJM-MISO interface to ensure this new transaction is only used for the pseudo-tie exports into MISO, not for other generators or paths. Each Day-Ahead Pseudo-Tie Transaction must also have transmission service reserved for the transaction and may not exceed the amount of the transmission service reservation to ensure the Day-Ahead Pseudo-Tie Transaction is only used to limit financial risk for a physical export transaction in the real-time energy market using the day-ahead energy market (i.e., ensure Day-Ahead Pseudo-Tie Transaction are not used as credit-free virtual transactions). For each Day-Ahead Pseudo-Tie Transaction, a market participant must specify the maximum difference between the locational marginal prices at the source and sink

(i.e., the maximum amount a market participant is willing to pay for congestion from the generator to the PJM-MISO interface). PJM will clear and schedule the transaction in the day-ahead energy market if the congestion charges for the transaction are less than the amount specified by the market participant.

2. *New Section 3.8 in the Appendix to Attachment K of the PJM Tariff and Schedule 1 of the Operating Agreement*

As described above in section II.B, PJM proposes to add new section 3.8 to the PJM Tariff and Operating Agreement to charge or credit market participants for deviations between day-ahead schedules and real-time generation from the market participant's pseudo-tie generator within MISO to the PJM-MISO interface for transmission congestion resulting from market-to-market coordination. Section 3.8 contains the formulas for such charges and credits.

3. *Revisions to Schedule 9-3 of the PJM Tariff*

PJM proposes to revise schedule 9-3 of the PJM Tariff to include Day-Ahead Pseudo-Tie Transactions in the list of transaction types from which PJM recovers costs for administering the energy markets. In carrying out its various responsibilities as a regional transmission organization, PJM incurs significant administrative costs recovered through various schedules in the PJM Tariff. Under schedule 9-3, PJM recovers costs for activities performed by PJM for the operation of PJM's energy markets and related functions. PJM recovers these costs by charging, among others, market participants that submit offers to sell or bids to buy energy in the PJM energy markets. As described in new section 1.10, Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink. Therefore, it is appropriate to charge Day-Ahead Pseudo-Tie Transactions for the administrative costs to support the bidding of such transactions.

4. *New and Revised Definitions in the PJM Tariff and Operating Agreement*

PJM proposes to revise the PJM Tariff and Operating Agreement with the following new and revised definitions to implement Day-Ahead Pseudo-Tie Transactions and charges for deviations between day-ahead and real-time pseudo-tie transactions from MISO into PJM;

- i. a new definition for Day-Ahead Pseudo-Tie Transaction consistent with the descriptions above;
- ii. revisions to the definition of Balancing Congestion Charges to include the new balancing deviations charges and credits under new section 3.8 in the formula for calculating congestion charges;
- iii. revisions to the definition of Day-Ahead Energy Market Injection Congestion Credits to include Day-Ahead Pseudo-Tie Transactions as a type of supply transaction in the day-ahead energy market for which market participants are paid congestion credits;
- iv. revisions to the definition of Day-Ahead Energy Market Withdrawal Congestion Charges to include Day-Ahead Pseudo-Tie Transactions as a type of withdrawal transaction in the day-ahead energy market for which market participants are charged congestion; and
- v. a new definition for “M2M Flowgate,” the flowgates on which the market-to-market coordination and resulting transmission congestion settlement occur and for which market participants are charged or credited under new section 3.8 described above.

### **III. STAKEHOLDER PROCESS**

The PJM Markets and Reliability Committee endorsed the revisions to the PJM Tariff and Operating Agreement proposed herein by acclamation with no objections and two abstentions at its March 22, 2018 meeting. The PJM Members Committee endorsed the revisions to the PJM Tariff and approved the revisions to the Operating Agreement by acclamation with no objections and no abstentions at its March 22, 2018 meeting.

### **IV. EFFECTIVE DATE**

PJM requests an effective date of August 1, 2018, for the revisions to the PJM Tariff and Operating Agreement proposed in this filing.

### **V. DOCUMENTS ENCLOSED**

Along with this transmittal letter, PJM submits the following attachments:

1. Attachment 1: an electronic version of the redlined sections of the PJM Tariff and Operating Agreement with the revisions proposed herein; and
2. Attachment 2: an electronic version of the clean sections of the PJM Tariff and Operating Agreement with the revisions proposed herein.

### **VI. CORRESPONDENCE AND COMMUNICATIONS**

Correspondence and communications regarding this filing should be sent to the following individuals:

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## **VII. SERVICE**

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,<sup>3</sup> PJM will post a copy of this filing to the FERC Filings section of its Web site, located at <http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx>, with a specific link to the newly filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region<sup>4</sup> alerting them of the filing and its availability on PJM's Web site. PJM also serves the parties listed on the Commission's official service list for this docket. Notwithstanding the foregoing, if the document is not immediately available by using the referenced link, it will be available within 24 hours of the filing. A copy of this filing will also be available on the Commission's eLibrary Web site located at <http://www.ferc.gov/docs-filing/elibrary.asp> in accordance with the Commission's regulations and Order No. 714.

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<sup>3</sup> See 18C.F.R §§ 35.2(e) and 385.2010(f)(3).

<sup>4</sup> PJM already maintains updates and regularly uses e-mail lists for all PJM members and affected state commissions.

## **VIII. CONCLUSION**

Wherefore, for the foregoing reasons, PJM respectfully requests that the Commission accept the revisions to the PJM Tariff and Operating Agreement proposed in this filing.

Respectfully submitted,



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# Attachment A

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

(Marked / Redline Format)

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

## **TABLE OF CONTENTS**

### **I. COMMON SERVICE PROVISIONS**

- 1 Definitions**
  - OATT Definitions – A – B**
  - OATT Definitions – C – D**
  - OATT Definitions – E – F**
  - OATT Definitions – G – H**
  - OATT Definitions – I – J – K**
  - OATT Definitions – L – M – N**
  - OATT Definitions – O – P – Q**
  - OATT Definitions – R – S**
  - OATT Definitions – T – U – V**
  - OATT Definitions – W – X – Y – Z**
- 2 Initial Allocation and Renewal Procedures**
- 3 Ancillary Services**
- 3B PJM Administrative Service**
- 3C Mid-Atlantic Area Council Charge**
- 3D Transitional Market Expansion Charge**
- 3E Transmission Enhancement Charges**
- 3F Transmission Losses**
- 4 Open Access Same-Time Information System (OASIS)**
- 5 Local Furnishing Bonds**
- 6 Reciprocity**
- 6A Counterparty**
- 7 Billing and Payment**
- 8 Accounting for a Transmission Owner's Use of the Tariff**
- 9 Regulatory Filings**
- 10 Force Majeure and Indemnification**
- 11 Creditworthiness**
- 12 Dispute Resolution Procedures**
- 12A PJM Compliance Review**

### **II. POINT-TO-POINT TRANSMISSION SERVICE**

#### **Preamble**

- 13 Nature of Firm Point-To-Point Transmission Service**
- 14 Nature of Non-Firm Point-To-Point Transmission Service**
- 15 Service Availability**
- 16 Transmission Customer Responsibilities**
- 17 Procedures for Arranging Firm Point-To-Point Transmission Service**
- 18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service**
- 19 Firm Transmission Feasibility Study Procedures For Long-Term Firm Point-To-Point Transmission Service Requests**
- 20 [Reserved]**

- 21 [Reserved]
- 22 Changes in Service Specifications
- 23 Sale or Assignment of Transmission Service
- 24 Metering and Power Factor Correction at Receipt and Delivery Points(s)
- 25 Compensation for Transmission Service
- 26 Stranded Cost Recovery
- 27 Compensation for New Facilities and Redispatch Costs
- 27A Distribution of Revenues from Non-Firm Point-to-Point Transmission Service

### **III. NETWORK INTEGRATION TRANSMISSION SERVICE**

#### **Preamble**

- 28 Nature of Network Integration Transmission Service
- 29 Initiating Service
- 30 Network Resources
- 31 Designation of Network Load
- 32 Firm Transmission Feasibility Study Procedures For Network Integration Transmission Service Requests
- 33 Load Shedding and Curtailments
- 34 Rates and Charges
- 35 Operating Arrangements

### **IV. INTERCONNECTIONS WITH THE TRANSMISSION SYSTEM**

#### **Preamble**

#### **Subpart A –INTERCONNECTION PROCEDURES**

- 36 Interconnection Requests
- 37 Additional Procedures
- 38 Service on Merchant Transmission Facilities
- 39 Local Furnishing Bonds

40-108 [Reserved]

Subpart B – [Reserved]

Subpart C – [Reserved]

Subpart D – [Reserved]

Subpart E – [Reserved]

Subpart F – [Reserved]

#### **Subpart G – SMALL GENERATION INTERCONNECTION PROCEDURE**

#### **Preamble**

- 109 Pre-application Process
- 110 Permanent Capacity Resource Additions Of 20 MW Or Less
- 111 Permanent Energy Resource Additions Of 20 MW Or Less but Greater than 2 MW (Synchronous) or Greater than 5 MW(Inverter-based)
- 112 Temporary Energy Resource Additions Of 20 MW Or Less But Greater Than 2 MW
- 112A Screens Process for Permanent or Temporary Energy Resources of 2 MW or less (Synchronous) or 5 MW (Inverter-based)

- 112B Certified Inverter-Based Small Generating Facilities No Larger than 10 kW
- 112C [Reserved]

**V. GENERATION DEACTIVATION**

**Preamble**

- 113 Notices
- 114 Deactivation Avoidable Cost Credit
- 115 Deactivation Avoidable Cost Rate
- 116 Filing and Updating of Deactivation Avoidable Cost Rate
  - 117 Excess Project Investment Required
  - 118 Refund of Project Investment Reimbursement
  - 118A Recovery of Project Investment
  - 119 Cost of Service Recovery Rate
  - 120 Cost Allocation
  - 121 Performance Standards
  - 122 Black Start Units
  - 123-199 [Reserved]

**VI. ADMINISTRATION AND STUDY OF NEW SERVICE REQUESTS; RIGHTS ASSOCIATED WITH CUSTOMER-FUNDED UPGRADES**

**Preamble**

- 200 Applicability
- 201 Queue Position
  - Subpart A – SYSTEM IMPACT STUDIES AND FACILITIES STUDIES FOR NEW SERVICE REQUESTS
- 202 Coordination with Affected Systems
- 203 System Impact Study Agreement
- 204 Tender of System Impact Study Agreement
- 205 System Impact Study Procedures
- 206 Facilities Study Agreement
- 207 Facilities Study Procedures
- 208 Expedited Procedures for Part II Requests
- 209 Optional Interconnection Studies
- 210 Responsibilities of the Transmission Provider and Transmission Owners
  - Subpart B– AGREEMENTS AND COST RESPONSIBILITY FOR CUSTOMER- FUNDED UPGRADES
- 211 Interim Interconnection Service Agreement
- 212 Interconnection Service Agreement
- 213 Upgrade Construction Service Agreement
- 214 Filing/Reporting of Agreement
- 215 Transmission Service Agreements
- 216 Interconnection Requests Designated as Market Solutions
- 217 Cost Responsibility for Necessary Facilities and Upgrades
- 218 New Service Requests Involving Affected Systems
- 219 Inter-queue Allocation of Costs of Transmission Upgrades

- 220 Advance Construction of Certain Network Upgrades**
- 221 Transmission Owner Construction Obligation for Necessary Facilities And Upgrades**
- 222 Confidentiality**
- 223 Confidential Information**
- 224 – 229 [Reserved]**
- Subpart C – RIGHTS RELATED TO CUSTOMER-FUNDED UPGRADES**
- 230 Capacity Interconnection Rights**
- 231 Incremental Auction Revenue Rights**
- 232 Transmission Injection Rights and Transmission Withdrawal Rights**
- 233 Incremental Available Transfer Capability Revenue Rights**
- 234 Incremental Capacity Transfer Rights**
- 235 Incremental Deliverability Rights**
- 236 Interconnection Rights for Certain Transmission Interconnections**
- 237 IDR Transfer Agreements**

#### **SCHEDULE 1**

**Scheduling, System Control and Dispatch Service**

#### **SCHEDULE 1A**

**Transmission Owner Scheduling, System Control and Dispatch Service**

#### **SCHEDULE 2**

**Reactive Supply and Voltage Control from Generation Sources Service**

#### **SCHEDULE 3**

**Regulation and Frequency Response Service**

#### **SCHEDULE 4**

**Energy Imbalance Service**

#### **SCHEDULE 5**

**Operating Reserve – Synchronized Reserve Service**

#### **SCHEDULE 6**

**Operating Reserve - Supplemental Reserve Service**

#### **SCHEDULE 6A**

**Black Start Service**

#### **SCHEDULE 7**

**Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service**

#### **SCHEDULE 8**

**Non-Firm Point-To-Point Transmission Service**

#### **SCHEDULE 9**

**PJM Interconnection L.L.C. Administrative Services**

#### **SCHEDULE 9-1**

**Control Area Administration Service**

#### **SCHEDULE 9-2**

**Financial Transmission Rights Administration Service**

#### **SCHEDULE 9-3**

**Market Support Service**

#### **SCHEDULE 9-4**



**Regulation and Frequency Response Administration Service**  
**SCHEDULE 9-5**  
**Capacity Resource and Obligation Management Service**  
**SCHEDULE 9-6**  
**Management Service Cost**  
**SCHEDULE 9-FERC**  
**FERC Annual Charge Recovery**  
**SCHEDULE 9-OPSI**  
**OPSI Funding**  
**SCHEDULE 9-CAPS**  
**CAPS Funding**  
**SCHEDULE 9-FINCON**  
**Finance Committee Retained Outside Consultant**  
**SCHEDULE 9-MMU**  
**MMU Funding**  
**SCHEDULE 9 – PJM SETTLEMENT**  
**SCHEDULE 10 - [Reserved]**  
**SCHEDULE 10-NERC**  
**North American Electric Reliability Corporation Charge**  
**SCHEDULE 10-RFC**  
**Reliability First Corporation Charge**  
**SCHEDULE 11**  
**[Reserved for Future Use]**  
**SCHEDULE 11A**  
**Additional Secure Control Center Data Communication Links and Formula Rate**  
**SCHEDULE 12**  
**Transmission Enhancement Charges**  
**SCHEDULE 12 APPENDIX**  
**SCHEDULE 12-A**  
**SCHEDULE 13**  
**Expansion Cost Recovery Change (ECRC)**  
**SCHEDULE 14**  
**Transmission Service on the Neptune Line**  
**SCHEDULE 14 - Exhibit A**  
**SCHEDULE 15**  
**Non-Retail Behind The Meter Generation Maximum Generation Emergency Obligations**  
**SCHEDULE 16**  
**Transmission Service on the Linden VFT Facility**  
**SCHEDULE 16 Exhibit A**  
**SCHEDULE 16 – A**  
**Transmission Service for Imports on the Linden VFT Facility**  
**SCHEDULE 17**  
**Transmission Service on the Hudson Line**  
**SCHEDULE 17 - Exhibit A**  
**ATTACHMENT A**

**Form of Service Agreement For Firm Point-To-Point Transmission Service**  
**ATTACHMENT A-1**  
**Form of Service Agreement For The Resale, Reassignment or Transfer of Point-to-Point Transmission Service**  
**ATTACHMENT B**  
**Form of Service Agreement For Non-Firm Point-To-Point Transmission Service**  
**ATTACHMENT C**  
**Methodology To Assess Available Transfer Capability**  
**ATTACHMENT C-1**  
**Conversion of Service in the Dominion and Duquesne Zones**  
**ATTACHMENT C-2**  
**Conversion of Service in the Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc, (“DEOK”) Zone**  
**ATTACHMENT C-4**  
**Conversion of Service in the OVEC Zone**  
**ATTACHMENT D**  
**Methodology for Completing a System Impact Study**  
**ATTACHMENT E**  
**Index of Point-To-Point Transmission Service Customers**  
**ATTACHMENT F**  
**Service Agreement For Network Integration Transmission Service**  
**ATTACHMENT F-1**  
**Form of Umbrella Service Agreement for Network Integration Transmission Service Under State Required Retail Access Programs**  
**ATTACHMENT G**  
**Network Operating Agreement**  
**ATTACHMENT H-1**  
**Annual Transmission Rates -- Atlantic City Electric Company for Network Integration Transmission Service**  
**ATTACHMENT H-1A**  
**Atlantic City Electric Company Formula Rate Appendix A**  
**ATTACHMENT H-1B**  
**Atlantic City Electric Company Formula Rate Implementation Protocols**  
**ATTACHMENT H-2**  
**Annual Transmission Rates -- Baltimore Gas and Electric Company for Network Integration Transmission Service**  
**ATTACHMENT H-2A**  
**Baltimore Gas and Electric Company Formula Rate**  
**ATTACHMENT H-2B**  
**Baltimore Gas and Electric Company Formula Rate Implementation Protocols**  
**ATTACHMENT H-3**  
**Annual Transmission Rates -- Delmarva Power & Light Company for Network Integration Transmission Service**  
**ATTACHMENT H-3A**  
**Delmarva Power & Light Company Load Power Factor Charge Applicable to Service the Interconnection Points**

**ATTACHMENT H-3B**

**Delmarva Power & Light Company Load Power Factor Charge Applicable to Service the Interconnection Points**

**ATTACHMENT H-3C**

**Delmarva Power & Light Company Under-Frequency Load Shedding Charge**

**ATTACHMENT H-3D**

**Delmarva Power & Light Company Formula Rate – Appendix A**

**ATTACHMENT H-3E**

**Delmarva Power & Light Company Formula Rate Implementation Protocols**

**ATTACHMENT H-3F**

**Old Dominion Electric Cooperative Formula Rate – Appendix A**

**ATTACHMENT H-3G**

**Old Dominion Electric Cooperative Formula Rate Implementation Protocols**

**ATTACHMENT H-4**

**Annual Transmission Rates -- Jersey Central Power & Light Company for Network Integration Transmission Service**

**ATTACHMENT H-4A**

**Other Supporting Facilities - Jersey Central Power & Light Company**

**ATTACHMENT H-4B**

**Jersey Central Power & Light Company – [Reserved]**

**ATTACHMENT H-5**

**Annual Transmission Rates -- Metropolitan Edison Company for Network Integration Transmission Service**

**ATTACHMENT H-5A**

**Other Supporting Facilities -- Metropolitan Edison Company**

**ATTACHMENT H-6**

**Annual Transmission Rates -- Pennsylvania Electric Company for Network Integration Transmission Service**

**ATTACHMENT H-6A**

**Other Supporting Facilities Charges -- Pennsylvania Electric Company**

**ATTACHMENT H-7**

**Annual Transmission Rates -- PECO Energy Company for Network Integration Transmission Service**

**ATTACHMENT H-7A**

**PECO Energy Company Formula Rate Template**

**ATTACHMENT H-7B**

**PECO Energy Company Monthly Deferred Tax Adjustment Charge**

**ATTACHMENT H-7C**

**PECO Energy Company Formula Rate Implementation Protocols**

**ATTACHMENT H-8**

**Annual Transmission Rates – PPL Group for Network Integration Transmission Service**

**ATTACHMENT H-8A**

**Other Supporting Facilities Charges -- PPL Electric Utilities Corporation**

**ATTACHMENT 8C**

**UGI Utilities, Inc. Formula Rate – Appendix A**

**ATTACHMENT 8D**

**UGI Utilities, Inc. Formula Rate Implementation Protocols**

**ATTACHMENT 8E**

**UGI Utilities, Inc. Formula Rate – Appendix A**

**ATTACHMENT H-8G**

**Annual Transmission Rates – PPL Electric Utilities Corp.**

**ATTACHMENT H-8H**

**Formula Rate Implementation Protocols – PPL Electric Utilities Corp.**

**ATTACHMENT H-9**

**Annual Transmission Rates -- Potomac Electric Power Company for Network Integration Transmission Service**

**ATTACHMENT H-9A**

**Potomac Electric Power Company Formula Rate – Appendix A**

**ATTACHMENT H-9B**

**Potomac Electric Power Company Formula Rate Implementation Protocols**

**ATTACHMENT H-9C**

**Annual Transmission Rate – Southern Maryland Electric Cooperative, Inc. for Network Integration Transmission Service**

**ATTACHMENT H-10**

**Annual Transmission Rates -- Public Service Electric and Gas Company for Network Integration Transmission Service**

**ATTACHMENT H-10A**

**Formula Rate -- Public Service Electric and Gas Company**

**ATTACHMENT H-10B**

**Formula Rate Implementation Protocols – Public Service Electric and Gas Company**

**ATTACHMENT H-11**

**Annual Transmission Rates -- Allegheny Power for Network Integration Transmission Service**

**ATTACHMENT 11A**

**Other Supporting Facilities Charges - Allegheny Power**

**ATTACHMENT H-12**

**Annual Transmission Rates -- Rockland Electric Company for Network Integration Transmission Service**

**ATTACHMENT H-13**

**Annual Transmission Rates – Commonwealth Edison Company for Network Integration Transmission Service**

**ATTACHMENT H-13A**

**Commonwealth Edison Company Formula Rate – Appendix A**

**ATTACHMENT H-13B**

**Commonwealth Edison Company Formula Rate Implementation Protocols**

**ATTACHMENT H-14**

**Annual Transmission Rates – AEP East Operating Companies for Network Integration Transmission Service**

**ATTACHMENT H-14A**

**AEP East Operating Companies Formula Rate Implementation Protocols**

**ATTACHMENT H-14B Part 1**

**ATTACHMENT H-14B Part 2**

**ATTACHMENT H-15**

**Annual Transmission Rates -- The Dayton Power and Light Company  
for Network Integration Transmission Service**

**ATTACHMENT H-16**

**Annual Transmission Rates -- Virginia Electric and Power Company  
for Network Integration Transmission Service**

**ATTACHMENT H-16A**

**Formula Rate - Virginia Electric and Power Company**

**ATTACHMENT H-16B**

**Formula Rate Implementation Protocols - Virginia Electric and Power Company**

**ATTACHMENT H-16C**

**Virginia Retail Administrative Fee Credit for Virginia Retail Load Serving  
Entities in the Dominion Zone**

**ATTACHMENT H-16D – [Reserved]**

**ATTACHMENT H-16E – [Reserved]**

**ATTACHMENT H-16AA**

**Virginia Electric and Power Company**

**ATTACHMENT H-17**

**Annual Transmission Rates -- Duquesne Light Company for Network Integration  
Transmission Service**

**ATTACHMENT H-17A**

**Duquesne Light Company Formula Rate – Appendix A**

**ATTACHMENT H-17B**

**Duquesne Light Company Formula Rate Implementation Protocols**

**ATTACHMENT H-17C**

**Duquesne Light Company Monthly Deferred Tax Adjustment Charge**

**ATTACHMENT H-18**

**Annual Transmission Rates – Trans-Allegheny Interstate Line Company**

**ATTACHMENT H-18A**

**Trans-Allegheny Interstate Line Company Formula Rate – Appendix A**

**ATTACHMENT H-18B**

**Trans-Allegheny Interstate Line Company Formula Rate Implementation Protocols**

**ATTACHMENT H-19**

**Annual Transmission Rates – Potomac-Appalachian Transmission Highline, L.L.C.**

**ATTACHMENT H-19A**

**Potomac-Appalachian Transmission Highline, L.L.C. Summary**

**ATTACHMENT H-19B**

**Potomac-Appalachian Transmission Highline, L.L.C. Formula Rate  
Implementation Protocols**

**ATTACHMENT H-20**

**Annual Transmission Rates – AEP Transmission Companies (AEPTCo) in the AEP  
Zone**

**ATTACHMENT H-20A**

**AEP Transmission Companies (AEPTCo) in the AEP Zone - Formula Rate Implementation Protocols**  
**ATTACHMENT H-20A APPENDIX A**  
**Transmission Formula Rate Settlement for AEPTCo**  
**ATTACHMENT H-20B - Part I**  
**AEP Transmission Companies (AEPTCo) in the AEP Zone – Blank Formula Rate Template**  
**ATTACHMENT H-20B - Part II**  
**AEP Transmission Companies (AEPTCo) in the AEP Zone – Blank Formula Rate Template**  
**ATTACHMENT H-21**  
**Annual Transmission Rates – American Transmission Systems, Inc. for Network Integration Transmission Service**  
**ATTACHMENT H-21A - ATSI**  
**ATTACHMENT H-21A Appendix A - ATSI**  
**ATTACHMENT H-21A Appendix B - ATSI**  
**ATTACHMENT H-21A Appendix C - ATSI**  
**ATTACHMENT H-21A Appendix C - ATSI [Reserved]**  
**ATTACHMENT H-21A Appendix D – ATSI**  
**ATTACHMENT H-21A Appendix E - ATSI**  
**ATTACHMENT H-21A Appendix F – ATSI [Reserved]**  
**ATTACHMENT H-21A Appendix G - ATSI**  
**ATTACHMENT H-21A Appendix G – ATSI (Credit Adj)**  
**ATTACHMENT H-21B ATSI Protocol**  
**ATTACHMENT H-22**  
**Annual Transmission Rates – DEOK for Network Integration Transmission Service and Point-to-Point Transmission Service**  
**ATTACHMENT H-22A**  
**Duke Energy Ohio and Duke Energy Kentucky (DEOK) Formula Rate Template**  
**ATTACHMENT H-22B**  
**DEOK Formula Rate Implementation Protocols**  
**ATTACHMENT H-22C**  
**Additional provisions re DEOK and Indiana**  
**ATTACHMENT H-23**  
**EP Rock springs annual transmission Rate**  
**ATTACHMENT H-24**  
**EKPC Annual Transmission Rates**  
**ATTACHMENT H-24A APPENDIX A**  
**EKPC Schedule 1A**  
**ATTACHMENT H-24A APPENDIX B**  
**EKPC RTEP**  
**ATTACHMENT H-24A APPENDIX C**  
**EKPC True-up**  
**ATTACHMENT H-24A APPENDIX D**  
**EKPC Depreciation Rates**  
**ATTACHMENT H-24-B**

	<b>EKPC Implementation Protocols</b>
<b>ATTACHMENT H-25</b>	<b>Annual Transmission Rates – Rochelle Municipal Utilities for Network Integration Transmission Service and Point-to-Point Transmission Service in the ComEd Zone</b>
<b>ATTACHMENT H-25A</b>	<b>Formula Rate Protocols for Rochelle Municipal Utilities Using a Historical Formula Rate Template</b>
<b>ATTACHMENT H-25B</b>	<b>Rochelle Municipal Utilities Transmission Cost of Service Formula Rate – Appendix A – Transmission Service Revenue Requirement</b>
<b>ATTACHMENT H-26</b>	<b>Transource West Virginia, LLC Formula Rate Template</b>
<b>ATTACHMENT H-26A</b>	<b>Transource West Virginia, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-27</b>	<b>Annual Transmission Rates – Northeast Transmission Development, LLC</b>
<b>ATTACHMENT H-27A</b>	<b>Northeast Transmission Development, LLC Formula Rate Template</b>
<b>ATTACHMENT H-27B</b>	<b>Northeast Transmission Development, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-28</b>	<b>Annual Transmission Rates – Mid-Atlantic Interstate Transmission, LLC for Network Integration Transmission Service</b>
<b>ATTACHMENT H-28A</b>	<b>Mid-Atlantic Interstate Transmission, LLC Formula Rate Template</b>
<b>ATTACHMENT H-28B</b>	<b>Mid-Atlantic Interstate Transmission, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-29</b>	<b>Annual Transmission Rates – Transource Pennsylvania, LLC</b>
<b>ATTACHMENT H-29A</b>	<b>Transource Pennsylvania, LLC Formula Rate Template</b>
<b>ATTACHMENT H-29B</b>	<b>Transource Pennsylvania, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-30</b>	<b>Annual Transmission Rates – Transource Maryland, LLC</b>
<b>ATTACHMENT H-30A</b>	<b>Transource Maryland, LLC Formula Rate Template</b>
<b>ATTACHMENT H-30B</b>	<b>Transource Maryland, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-31</b>	<b>Annual Transmission Revenue Requirement – Ohio Valley Electric Corporation for Network Integration Transmission Service</b>
<b>ATTACHMENT H-A</b>	

**Annual Transmission Rates -- Non-Zone Network Load for Network Integration  
Transmission Service**

**ATTACHMENT I**

**Index of Network Integration Transmission Service Customers**

**ATTACHMENT J**

**PJM Transmission Zones**

**ATTACHMENT K**

**Transmission Congestion Charges and Credits**

**Preface**

**ATTACHMENT K -- APPENDIX**

**Preface**

**1. MARKET OPERATIONS**

- 1.1 Introduction
- 1.2 Cost-Based Offers
- 1.2A Transmission Losses
- 1.3 [Reserved for Future Use]
- 1.4 Market Buyers
- 1.5 Market Sellers
- 1.5A Economic Load Response Participant
- 1.6 Office of the Interconnection
- 1.6A PJM Settlement
- 1.7 General
- 1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process
- 1.9 Prescheduling
- 1.10 Scheduling
- 1.11 Dispatch
- 1.12 Dynamic Transfers

**2. CALCULATION OF LOCATIONAL MARGINAL PRICES**

- 2.1 Introduction
- 2.2 General
- 2.3 Determination of System Conditions Using the State Estimator
- 2.4 Determination of Energy Offers Used in Calculating
- 2.5 Calculation of Real-time Prices
- 2.6 Calculation of Day-ahead Prices
- 2.6A Interface Prices
- 2.7 Performance Evaluation

**3. ACCOUNTING AND BILLING**

- 3.1 Introduction
- 3.2 Market Buyers
- 3.3 Market Sellers
  - 3.3A Economic Load Response Participants
- 3.4 Transmission Customers
- 3.5 Other Control Areas
- 3.6 Metering Reconciliation
- 3.7 Inadvertent Interchange
- 3.8 Market-to-Market Coordination

**4. [Reserved For Future Use]**



- 5. CALCULATION OF CHARGES AND CREDITS FOR TRANSMISSION CONGESTION AND LOSSES**
  - 5.1 Transmission Congestion Charge Calculation
  - 5.2 Transmission Congestion Credit Calculation
  - 5.3 Unscheduled Transmission Service (Loop Flow)
  - 5.4 Transmission Loss Charge Calculation
  - 5.5 Distribution of Total Transmission Loss Charges
- 6. “MUST-RUN” FOR RELIABILITY GENERATION**
  - 6.1 Introduction
  - 6.2 Identification of Facility Outages
  - 6.3 Dispatch for Local Reliability
  - 6.4 Offer Price Caps
  - 6.5 [Reserved]
  - 6.6 Minimum Generator Operating Parameters –  
Parameter-Limited Schedules
- 6A. [Reserved]**
  - 6A.1 [Reserved]
  - 6A.2 [Reserved]
  - 6A.3 [Reserved]
- 7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS**
  - 7.1 Auctions of Financial Transmission Rights
  - 7.1A Long-Term Financial Transmission Rights Auctions
  - 7.2 Financial Transmission Rights Characteristics
  - 7.3 Auction Procedures
  - 7.4 Allocation of Auction Revenues
  - 7.5 Simultaneous Feasibility
  - 7.6 New Stage 1 Resources
  - 7.7 Alternate Stage 1 Resources
  - 7.8 Elective Upgrade Auction Revenue Rights
  - 7.9 Residual Auction Revenue Rights
  - 7.10 Financial Settlement
  - 7.11 PJM Settlement as Counterparty
- 8. EMERGENCY AND PRE-EMERGENCY LOAD RESPONSE PROGRAM**
  - 8.1 Emergency Load Response and Pre-Emergency Load Response Program Options
  - 8.2 Participant Qualifications
  - 8.3 Metering Requirements
  - 8.4 Registration
  - 8.5 Pre-Emergency Operations
  - 8.6 Emergency Operations
  - 8.7 Verification
  - 8.8 Market Settlements
  - 8.9 Reporting and Compliance
  - 8.10 Non-Hourly Metered Customer Pilot
  - 8.11 Emergency Load Response and Pre-Emergency Load Response Participant  
Aggregation

## **ATTACHMENT L**

<b>List of Transmission Owners</b>	
<b>ATTACHMENT M</b>	
<b>PJM Market Monitoring Plan</b>	
<b>ATTACHMENT M – APPENDIX</b>	
<b>PJM Market Monitor Plan Attachment M Appendix</b>	
I	Confidentiality of Data and Information
II	Development of Inputs for Prospective Mitigation
III	Black Start Service
IV	Deactivation Rates
V	Opportunity Cost Calculation
VI	FTR Forfeiture Rule
VII	Forced Outage Rule
VIII	Data Collection and Verification
<b>ATTACHMENT M-1 (FirstEnergy)</b>	
<b>Energy Procedure Manual for Determining Supplier Total Hourly Energy Obligation</b>	
<b>ATTACHMENT M-2 (First Energy)</b>	
<b>Energy Procedure Manual for Determining Supplier Peak Load Share Procedures for Load Determination</b>	
<b>ATTACHMENT M-2 (ComEd)</b>	
<b>Determination of Capacity Peak Load Contributions and Network Service Peak Load Contributions</b>	
<b>ATTACHMENT M-2 (PSE&amp;G)</b>	
<b>Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-2 (Atlantic City Electric Company)</b>	
<b>Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-2 (Delmarva Power &amp; Light Company)</b>	
<b>Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-2 (Delmarva Power &amp; Light Company)</b>	
<b>Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-2 (Duke Energy Ohio, Inc.)</b>	
<b>Procedures for Determination of Peak Load Contributions, Network Service Peak Load and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-3</b>	
<b>Additional Procedures for Planning of Supplemental Projects</b>	
<b>ATTACHMENT N</b>	
<b>Form of Generation Interconnection Feasibility Study Agreement</b>	
<b>ATTACHMENT N-1</b>	
<b>Form of System Impact Study Agreement</b>	
<b>ATTACHMENT N-2</b>	
<b>Form of Facilities Study Agreement</b>	
<b>ATTACHMENT N-3</b>	

**Form of Optional Interconnection Study Agreement**  
**ATTACHMENT O**

**Form of Interconnection Service Agreement**

- 1.0 Parties
- 2.0 Authority
- 3.0 Customer Facility Specifications
- 4.0 Effective Date
- 5.0 Security
- 6.0 Project Specific Milestones
- 7.0 Provision of Interconnection Service
- 8.0 Assumption of Tariff Obligations
- 9.0 Facilities Study
- 10.0 Construction of Transmission Owner Interconnection Facilities
- 11.0 Interconnection Specifications
- 12.0 Power Factor Requirement
- 12.0A RTU
- 13.0 Charges
- 14.0 Third Party Benefits
- 15.0 Waiver
- 16.0 Amendment
- 17.0 Construction With Other Parts Of The Tariff
- 18.0 Notices
- 19.0 Incorporation Of Other Documents
- 20.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service
- 21.0 Addendum of Interconnection Customer's Agreement  
to Conform with IRS Safe Harbor Provisions for Non-Taxable Status
- 22.0 Addendum of Interconnection Requirements for a Wind Generation Facility
- 23.0 Infrastructure Security of Electric System Equipment and Operations and Control  
Hardware and Software is Essential to Ensure Day-to-Day Reliability and  
Operational Security

**Specifications for Interconnection Service Agreement**

- 1.0 Description of [generating unit(s)] [Merchant Transmission Facilities] (the  
Customer Facility) to be Interconnected with the Transmission System in the PJM  
Region
- 2.0 Rights
- 3.0 Construction Responsibility and Ownership of Interconnection Facilities
- 4.0 Subject to Modification Pursuant to the Negotiated Contract Option
- 4.1 Attachment Facilities Charge
- 4.2 Network Upgrades Charge
- 4.3 Local Upgrades Charge
- 4.4 Other Charges
- 4.5 Cost breakdown
- 4.6 Security Amount Breakdown

**ATTACHMENT O APPENDIX 1: Definitions**

**ATTACHMENT O APPENDIX 2: Standard Terms and Conditions for Interconnections**

**1 Commencement, Term of and Conditions Precedent to**

- Interconnection Service**
  - 1.1 Commencement Date
  - 1.2 Conditions Precedent
  - 1.3 Term
  - 1.4 Initial Operation
  - 1.4A Limited Operation
  - 1.5 Survival
- 2 Interconnection Service**
  - 2.1 Scope of Service
  - 2.2 Non-Standard Terms
  - 2.3 No Transmission Services
  - 2.4 Use of Distribution Facilities
  - 2.5 Election by Behind The Meter Generation
- 3 Modification Of Facilities**
  - 3.1 General
  - 3.2 Interconnection Request
  - 3.3 Standards
  - 3.4 Modification Costs
- 4 Operations**
  - 4.1 General
  - 4.2 [Reserved]
  - 4.3 Interconnection Customer Obligations
  - 4.4 Transmission Interconnection Customer Obligations
  - 4.5 Permits and Rights-of-Way
  - 4.6 No Ancillary Services
  - 4.7 Reactive Power
  - 4.8 Under- and Over-Frequency and Under- and Over- Voltage Conditions
  - 4.9 System Protection and Power Quality
  - 4.10 Access Rights
  - 4.11 Switching and Tagging Rules
  - 4.12 Communications and Data Protocol
  - 4.13 Nuclear Generating Facilities
- 5 Maintenance**
  - 5.1 General
  - 5.2 [Reserved]
  - 5.3 Outage Authority and Coordination
  - 5.4 Inspections and Testing
  - 5.5 Right to Observe Testing
  - 5.6 Secondary Systems
  - 5.7 Access Rights
  - 5.8 Observation of Deficiencies
- 6 Emergency Operations**
  - 6.1 Obligations
  - 6.2 Notice
  - 6.3 Immediate Action
  - 6.4 Record-Keeping Obligations

- 7 Safety**
  - 7.1 General
  - 7.2 Environmental Releases
- 8 Metering**
  - 8.1 General
  - 8.2 Standards
  - 8.3 Testing of Metering Equipment
  - 8.4 Metering Data
  - 8.5 Communications
- 9 Force Majeure**
  - 9.1 Notice
  - 9.2 Duration of Force Majeure
  - 9.3 Obligation to Make Payments
  - 9.4 Definition of Force Majeure
- 10 Charges**
  - 10.1 Specified Charges
  - 10.2 FERC Filings
- 11 Security, Billing And Payments**
  - 11.1 Recurring Charges Pursuant to Section 10
  - 11.2 Costs for Transmission Owner Interconnection Facilities
  - 11.3 No Waiver
  - 11.4 Interest
- 12 Assignment**
  - 12.1 Assignment with Prior Consent
  - 12.2 Assignment Without Prior Consent
  - 12.3 Successors and Assigns
- 13 Insurance**
  - 13.1 Required Coverages for Generation Resources Of More Than 20 Megawatts and Merchant Transmission Facilities
  - 13.1A Required Coverages for Generation Resources Of 20 Megawatts Or Less
  - 13.2 Additional Insureds
  - 13.3 Other Required Terms
  - 13.3A No Limitation of Liability
  - 13.4 Self-Insurance
  - 13.5 Notices; Certificates of Insurance
  - 13.6 Subcontractor Insurance
  - 13.7 Reporting Incidents
- 14 Indemnity**
  - 14.1 Indemnity
  - 14.2 Indemnity Procedures
  - 14.3 Indemnified Person
  - 14.4 Amount Owing
  - 14.5 Limitation on Damages
  - 14.6 Limitation of Liability in Event of Breach
  - 14.7 Limited Liability in Emergency Conditions

- 15 Breach, Cure And Default**
  - 15.1 Breach
  - 15.2 Continued Operation
  - 15.3 Notice of Breach
  - 15.4 Cure and Default
  - 15.5 Right to Compel Performance
  - 15.6 Remedies Cumulative
- 16 Termination**
  - 16.1 Termination
  - 16.2 Disposition of Facilities Upon Termination
  - 16.3 FERC Approval
  - 16.4 Survival of Rights
- 17 Confidentiality**
  - 17.1 Term
  - 17.2 Scope
  - 17.3 Release of Confidential Information
  - 17.4 Rights
  - 17.5 No Warranties
  - 17.6 Standard of Care
  - 17.7 Order of Disclosure
  - 17.8 Termination of Interconnection Service Agreement
  - 17.9 Remedies
  - 17.10 Disclosure to FERC or its Staff
  - 17.11 No Interconnection Party Shall Disclose Confidential Information
  - 17.12 Information that is Public Domain
  - 17.13 Return or Destruction of Confidential Information
- 18 Subcontractors**
  - 18.1 Use of Subcontractors
  - 18.2 Responsibility of Principal
  - 18.3 Indemnification by Subcontractors
  - 18.4 Subcontractors Not Beneficiaries
- 19 Information Access And Audit Rights**
  - 19.1 Information Access
  - 19.2 Reporting of Non-Force Majeure Events
  - 19.3 Audit Rights
- 20 Disputes**
  - 20.1 Submission
  - 20.2 Rights Under The Federal Power Act
  - 20.3 Equitable Remedies
- 21 Notices**
  - 21.1 General
  - 21.2 Emergency Notices
  - 21.3 Operational Contacts
- 22 Miscellaneous**
  - 22.1 Regulatory Filing
  - 22.2 Waiver

	22.3	Amendments and Rights Under the Federal Power Act
	22.4	Binding Effect
	22.5	Regulatory Requirements
<b>23</b>		<b>Representations And Warranties</b>
	23.1	General
<b>24</b>		<b>Tax Liability</b>
	24.1	Safe Harbor Provisions
	24.2	Tax Indemnity
	24.3	Taxes Other Than Income Taxes
	24.4	Income Tax Gross-Up
	24.5	Tax Status
<b>ATTACHMENT O - SCHEDULE A</b>		
		<b>Customer Facility Location/Site Plan</b>
<b>ATTACHMENT O - SCHEDULE B</b>		
		<b>Single-Line Diagram</b>
<b>ATTACHMENT O - SCHEDULE C</b>		
		<b>List of Metering Equipment</b>
<b>ATTACHMENT O - SCHEDULE D</b>		
		<b>Applicable Technical Requirements and Standards</b>
<b>ATTACHMENT O - SCHEDULE E</b>		
		<b>Schedule of Charges</b>
<b>ATTACHMENT O - SCHEDULE F</b>		
		<b>Schedule of Non-Standard Terms &amp; Conditions</b>
<b>ATTACHMENT O - SCHEDULE G</b>		
		<b>Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status</b>
<b>ATTACHMENT O - SCHEDULE H</b>		
		<b>Interconnection Requirements for a Wind Generation Facility</b>
<b>ATTACHMENT O-1</b>		
		<b>Form of Interim Interconnection Service Agreement</b>
<b>ATTACHMENT P</b>		
		<b>Form of Interconnection Construction Service Agreement</b>
	1.0	Parties
	2.0	Authority
	3.0	Customer Facility
	4.0	Effective Date and Term
	4.1	Effective Date
	4.2	Term
	4.3	Survival
	5.0	Construction Responsibility
	6.0	[Reserved.]
	7.0	Scope of Work
	8.0	Schedule of Work
	9.0	[Reserved.]
	10.0	Notices
	11.0	Waiver

- 12.0 Amendment
- 13.0 Incorporation Of Other Documents
- 14.0 Addendum of Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status
- 15.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service
- 16.0 Addendum of Interconnection Requirements for a Wind Generation Facility
- 17.0 Infrastructure Security of Electric System Equipment and Operations and Control Hardware and Software is Essential to Ensure Day-to-Day Reliability and Operational Security

## **ATTACHMENT P - APPENDIX 1 – DEFINITIONS**

## **ATTACHMENT P - APPENDIX 2 – STANDARD CONSTRUCTION TERMS AND CONDITIONS**

### **Preamble**

#### **1 Facilitation by Transmission Provider**

#### **2 Construction Obligations**

- 2.1 Interconnection Customer Obligations
- 2.2 Transmission Owner Interconnection Facilities and Merchant Network Upgrades
- 2.2A Scope of Applicable Technical Requirements and Standards
- 2.3 Construction By Interconnection Customer
- 2.4 Tax Liability
- 2.5 Safety
- 2.6 Construction-Related Access Rights
- 2.7 Coordination Among Constructing Parties

#### **3 Schedule of Work**

- 3.1 Construction by Interconnection Customer
- 3.2 Construction by Interconnected Transmission Owner
  - 3.2.1 Standard Option
  - 3.2.2 Negotiated Contract Option
  - 3.2.3 Option to Build
- 3.3 Revisions to Schedule of Work
- 3.4 Suspension
  - 3.4.1 Costs
  - 3.4.2 Duration of Suspension
- 3.5 Right to Complete Transmission Owner Interconnection Facilities
- 3.6 Suspension of Work Upon Default
- 3.7 Construction Reports
- 3.8 Inspection and Testing of Completed Facilities
- 3.9 Energization of Completed Facilities
- 3.10 Interconnected Transmission Owner's Acceptance of Facilities Constructed by Interconnection Customer

#### **4 Transmission Outages**

- 4.1 Outages; Coordination

#### **5 Land Rights; Transfer of Title**

- 5.1 Grant of Easements and Other Land Rights



5.2	Construction of Facilities on Interconnection Customer Property
5.3	Third Parties
5.4	Documentation
5.5	Transfer of Title to Certain Facilities Constructed By Interconnection Customer
5.6	Liens
<b>6</b>	<b>Warranties</b>
6.1	Interconnection Customer Warranty
6.2	Manufacturer Warranties
<b>7</b>	<b>[Reserved.]</b>
<b>8</b>	<b>[Reserved.]</b>
<b>9</b>	<b>Security, Billing And Payments</b>
9.1	Adjustments to Security
9.2	Invoice
9.3	Final Invoice
9.4	Disputes
9.5	Interest
9.6	No Waiver
<b>10</b>	<b>Assignment</b>
10.1	Assignment with Prior Consent
10.2	Assignment Without Prior Consent
10.3	Successors and Assigns
<b>11</b>	<b>Insurance</b>
11.1	Required Coverages For Generation Resources Of More Than 20 Megawatts and Merchant Transmission Facilities
11.1A	Required Coverages For Generation Resources of 20 Megawatts Or Less
11.2	Additional Insureds
11.3	Other Required Terms
11.3A	No Limitation of Liability
11.4	Self-Insurance
11.5	Notices; Certificates of Insurance
11.6	Subcontractor Insurance
11.7	Reporting Incidents
<b>12</b>	<b>Indemnity</b>
12.1	Indemnity
12.2	Indemnity Procedures
12.3	Indemnified Person
12.4	Amount Owing
12.5	Limitation on Damages
12.6	Limitation of Liability in Event of Breach
12.7	Limited Liability in Emergency Conditions
<b>13</b>	<b>Breach, Cure And Default</b>
13.1	Breach
13.2	Notice of Breach
13.3	Cure and Default

	13.3.1	Cure of Breach
	13.4	Right to Compel Performance
	13.5	Remedies Cumulative
<b>14</b>		<b>Termination</b>
	14.1	Termination
	14.2	[Reserved.]
	14.3	Cancellation By Interconnection Customer
	14.4	Survival of Rights
<b>15</b>		<b>Force Majeure</b>
	15.1	Notice
	15.2	Duration of Force Majeure
	15.3	Obligation to Make Payments
	15.4	Definition of Force Majeure
<b>16</b>		<b>Subcontractors</b>
	16.1	Use of Subcontractors
	16.2	Responsibility of Principal
	16.3	Indemnification by Subcontractors
	16.4	Subcontractors Not Beneficiaries
<b>17</b>		<b>Confidentiality</b>
	17.1	Term
	17.2	Scope
	17.3	Release of Confidential Information
	17.4	Rights
	17.5	No Warranties
	17.6	Standard of Care
	17.7	Order of Disclosure
	17.8	Termination of Construction Service Agreement
	17.9	Remedies
	17.10	Disclosure to FERC or its Staff
	17.11	No Construction Party Shall Disclose Confidential Information of Another Construction Party 17.12 Information that is Public Domain
	17.13	Return or Destruction of Confidential Information
<b>18</b>		<b>Information Access And Audit Rights</b>
	18.1	Information Access
	18.2	Reporting of Non-Force Majeure Events
	18.3	Audit Rights
<b>19</b>		<b>Disputes</b>
	19.1	Submission
	19.2	Rights Under The Federal Power Act
	19.3	Equitable Remedies
<b>20</b>		<b>Notices</b>
	20.1	General
	20.2	Operational Contacts
<b>21</b>		<b>Miscellaneous</b>
	21.1	Regulatory Filing
	21.2	Waiver

21.3	Amendments and Rights under the Federal Power Act
21.4	Binding Effect
21.5	Regulatory Requirements
<b>22</b>	<b>Representations and Warranties</b>
22.1	General
<b>ATTACHMENT P - SCHEDULE A</b>	
	<b>Site Plan</b>
<b>ATTACHMENT P - SCHEDULE B</b>	
	<b>Single-Line Diagram of Interconnection Facilities</b>
<b>ATTACHMENT P - SCHEDULE C</b>	
	<b>Transmission Owner Interconnection Facilities to be Built by Interconnected Transmission Owner</b>
<b>ATTACHMENT P - SCHEDULE D</b>	
	<b>Transmission Owner Interconnection Facilities to be Built by Interconnection Customer Pursuant to Option to Build</b>
<b>ATTACHMENT P - SCHEDULE E</b>	
	<b>Merchant Network Upgrades to be Built by Interconnected Transmission Owner</b>
<b>ATTACHMENT P - SCHEDULE F</b>	
	<b>Merchant Network Upgrades to be Built by Interconnection Customer Pursuant to Option to Build</b>
<b>ATTACHMENT P - SCHEDULE G</b>	
	<b>Customer Interconnection Facilities</b>
<b>ATTACHMENT P - SCHEDULE H</b>	
	<b>Negotiated Contract Option Terms</b>
<b>ATTACHMENT P - SCHEDULE I</b>	
	<b>Scope of Work</b>
<b>ATTACHMENT P - SCHEDULE J</b>	
	<b>Schedule of Work</b>
<b>ATTACHMENT P - SCHEDULE K</b>	
	<b>Applicable Technical Requirements and Standards</b>
<b>ATTACHMENT P - SCHEDULE L</b>	
	<b>Interconnection Customer's Agreement to Confirm with IRS Safe Harbor Provisions For Non-Taxable Status</b>
<b>ATTACHMENT P - SCHEDULE M</b>	
	<b>Schedule of Non-Standard Terms and Conditions</b>
<b>ATTACHMENT P - SCHEDULE N</b>	
	<b>Interconnection Requirements for a Wind Generation Facility</b>
<b>ATTACHMENT Q</b>	
	<b>PJM Credit Policy</b>
<b>ATTACHMENT R</b>	
	<b>Lost Revenues Of PJM Transmission Owners And Distribution of Revenues Remitted By MISO, SECA Rates to Collect PJM Transmission Owner Lost Revenues Under Attachment X, And Revenues From PJM Existing Transactions</b>
<b>ATTACHMENT S</b>	
	<b>Form of Transmission Interconnection Feasibility Study Agreement</b>
<b>ATTACHMENT T</b>	

	<b>Identification of Merchant Transmission Facilities</b>
<b>ATTACHMENT U</b>	<b>Independent Transmission Companies</b>
<b>ATTACHMENT V</b>	<b>Form of ITC Agreement</b>
<b>ATTACHMENT W</b>	<b>COMMONWEALTH EDISON COMPANY</b>
<b>ATTACHMENT X</b>	<b>Seams Elimination Cost Assignment Charges</b>
	<b>NOTICE OF ADOPTION OF NERC TRANSMISSION LOADING RELIEF PROCEDURES</b>
	<b>NOTICE OF ADOPTION OF LOCAL TRANSMISSION LOADING RELIEF PROCEDURES</b>
	<b>SCHEDULE OF PARTIES ADOPTING LOCAL TRANSMISSION LOADING RELIEF PROCEDURES</b>
<b>ATTACHMENT Y</b>	<b>Forms of Screens Process Interconnection Request (For Generation Facilities of 2 MW or less)</b>
<b>ATTACHMENT Z</b>	<b>Certification Codes and Standards</b>
<b>ATTACHMENT AA</b>	<b>Certification of Small Generator Equipment Packages</b>
<b>ATTACHMENT BB</b>	<b>Form of Certified Inverter-Based Generating Facility No Larger Than 10 kW Interconnection Service Agreement</b>
<b>ATTACHMENT CC</b>	<b>Form of Certificate of Completion (Small Generating Inverter Facility No Larger Than 10 kW)</b>
<b>ATTACHMENT DD</b>	<b>Reliability Pricing Model</b>
<b>ATTACHMENT EE</b>	<b>Form of Upgrade Request</b>
<b>ATTACHMENT FF</b>	<b>[Reserved]</b>
<b>ATTACHMENT GG</b>	<b>Form of Upgrade Construction Service Agreement</b>
	Article 1 – Definitions And Other Documents
	1.0 Defined Terms
	1.1 Incorporation of Other Documents
	Article 2 – Responsibility for Direct Assignment Facilities or Customer-Funded Upgrades
	2.0 New Service Customer Financial Responsibilities
	2.1 Obligation to Provide Security
	2.2 Failure to Provide Security
	2.3 Costs
	2.4 Transmission Owner Responsibilities

- Article 3 – Rights To Transmission Service
  - 3.0 No Transmission Service
- Article 4 – Early Termination
  - 4.0 Termination by New Service Customer
- Article 5 – Rights
  - 5.0 Rights
    - 5.1 Amount of Rights Granted
    - 5.2 Availability of Rights Granted
    - 5.3 Credits
- Article 6 – Miscellaneous
  - 6.0 Notices
  - 6.1 Waiver
  - 6.2 Amendment
  - 6.3 No Partnership
  - 6.4 Counterparts

**ATTACHMENT GG - APPENDIX I –**

**SCOPE AND SCHEDULE OF WORK FOR DIRECT ASSIGNMENT  
FACILITIES OR CUSTOMER-FUNDED UPGRADES TO BE BUILT BY  
TRANSMISSION OWNER**

**ATTACHMENT GG - APPENDIX II - DEFINITIONS**

- 1 Definitions
  - 1.1 Affiliate
  - 1.2 Applicable Laws and Regulations
  - 1.3 Applicable Regional Reliability Council
  - 1.4 Applicable Standards
  - 1.5 Breach
  - 1.6 Breaching Party
  - 1.7 Cancellation Costs
  - 1.8 Commission
  - 1.9 Confidential Information
  - 1.10 Constructing Entity
  - 1.11 Control Area
  - 1.12 Costs
  - 1.13 Default
  - 1.14 Delivering Party
  - 1.15 Emergency Condition
  - 1.16 Environmental Laws
  - 1.17 Facilities Study
  - 1.18 Federal Power Act
  - 1.19 FERC
  - 1.20 Firm Point-To-Point
  - 1.21 Force Majeure
  - 1.22 Good Utility Practice
  - 1.23 Governmental Authority
  - 1.24 Hazardous Substances
  - 1.25 Incidental Expenses

- 1.26 Local Upgrades
- 1.27 Long-Term Firm Point-To-Point Transmission Service
- 1.28 MAAC
- 1.29 MAAC Control Zone
- 1.30 NERC
- 1.31 Network Upgrades
- 1.32 Office of the Interconnection
- 1.33 Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement
- 1.34 Part I
- 1.35 Part II
- 1.36 Part III
- 1.37 Part IV
- 1.38 Part VI
- 1.39 PJM Interchange Energy Market
- 1.40 PJM Manuals
- 1.41 PJM Region
- 1.42 PJM West Region
- 1.43 Point(s) of Delivery
- 1.44 Point(s) of Receipt
- 1.45 Project Financing
- 1.46 Project Finance Entity
- 1.47 Reasonable Efforts
- 1.48 Receiving Party
- 1.49 Regional Transmission Expansion Plan
- 1.50 Schedule and Scope of Work
- 1.51 Security
- 1.52 Service Agreement
- 1.53 State
- 1.54 Transmission System
- 1.55 VACAR

## **ATTACHMENT GG - APPENDIX III – GENERAL TERMS AND CONDITIONS**

- 1.0 Effective Date and Term
  - 1.1 Effective Date
  - 1.2 Term
  - 1.3 Survival
- 2.0 Facilitation by Transmission Provider
- 3.0 Construction Obligations
  - 3.1 Direct Assignment Facilities or Customer-Funded Upgrades
  - 3.2 Scope of Applicable Technical Requirements and Standards
- 4.0 Tax Liability
  - 4.1 New Service Customer Payments Taxable
  - 4.2 Income Tax Gross-Up
  - 4.3 Private Letter Ruling
  - 4.4 Refund
  - 4.5 Contests

- 4.6 Taxes Other Than Income Taxes
  - 4.7 Tax Status
- 5.0 Safety
  - 5.1 General
  - 5.2 Environmental Releases
- 6.0 Schedule Of Work
  - 6.1 Standard Option
  - 6.2 Option to Build
  - 6.3 Revisions to Schedule and Scope of Work
  - 6.4 Suspension
- 7.0 Suspension of Work Upon Default
  - 7.1 Notification and Correction of Defects
- 8.0 Transmission Outages
  - 8.1 Outages; Coordination
- 9.0 Security, Billing and Payments
  - 9.1 Adjustments to Security
  - 9.2 Invoice
  - 9.3 Final Invoice
  - 9.4 Disputes
  - 9.5 Interest
  - 9.6 No Waiver
- 10.0 Assignment
  - 10.1 Assignment with Prior Consent
  - 10.2 Assignment Without Prior Consent
  - 10.3 Successors and Assigns
- 11.0 Insurance
  - 11.1 Required Coverages
  - 11.2 Additional Insureds
  - 11.3 Other Required Terms
  - 11.4 No Limitation of Liability
  - 11.5 Self-Insurance
  - 11.6 Notices: Certificates of Insurance
  - 11.7 Subcontractor Insurance
  - 11.8 Reporting Incidents
- 12.0 Indemnity
  - 12.1 Indemnity
  - 12.2 Indemnity Procedures
  - 12.3 Indemnified Person
  - 12.4 Amount Owing
  - 12.5 Limitation on Damages
  - 12.6 Limitation of Liability in Event of Breach
  - 12.7 Limited Liability in Emergency Conditions
- 13.0 Breach, Cure And Default
  - 13.1 Breach
  - 13.2 Notice of Breach
  - 13.3 Cure and Default

- 13.4 Right to Compel Performance
- 13.5 Remedies Cumulative
- 14.0 Termination
  - 14.1 Termination
  - 14.2 Cancellation By New Service Customer
  - 14.3 Survival of Rights
  - 14.4 Filing at FERC
- 15.0 Force Majeure
  - 15.1 Notice
  - 15.2 Duration of Force Majeure
  - 15.3 Obligation to Make Payments
- 16.0 Confidentiality
  - 16.1 Term
  - 16.2 Scope
  - 16.3 Release of Confidential Information
  - 16.4 Rights
  - 16.5 No Warranties
  - 16.6 Standard of Care
  - 16.7 Order of Disclosure
  - 16.8 Termination of Upgrade Construction Service Agreement
  - 16.9 Remedies
  - 16.10 Disclosure to FERC or its Staff
  - 16.11 No Party Shall Disclose Confidential Information of Party 16.12  
Information that is Public Domain
  - 16.13 Return or Destruction of Confidential Information
- 17.0 Information Access And Audit Rights
  - 17.1 Information Access
  - 17.2 Reporting of Non-Force Majeure Events
  - 17.3 Audit Rights
  - 17.4 Waiver
  - 17.5 Amendments and Rights under the Federal Power Act
  - 17.6 Regulatory Requirements
- 18.0 Representation and Warranties
  - 18.1 General
- 19.0 Inspection and Testing of Completed Facilities
  - 19.1 Coordination
  - 19.2 Inspection and Testing
  - 19.3 Review of Inspection and Testing by Transmission Owner
  - 19.4 Notification and Correction of Defects
  - 19.5 Notification of Results
- 20.0 Energization of Completed Facilities
- 21.0 Transmission Owner's Acceptance of Facilities Constructed  
by New Service Customer
- 22.0 Transfer of Title to Certain Facilities Constructed By New Service Customer
- 23.0 Liens



**ATTACHMENT HH – RATES, TERMS, AND CONDITIONS OF SERVICE FOR PJMSETTLEMENT, INC.**

**ATTACHMENT II – MTEP PROJECT COST RECOVERY FOR ATSI ZONE**

**ATTACHMENT JJ – MTEP PROJECT COST RECOVERY FOR DEOK ZONE**

**ATTACHMENT KK - FORM OF DESIGNATED ENTITY AGREEMENT**

**ATTACHMENT LL - FORM OF INTERCONNECTION COORDINATION AGREEMENT**

**ATTACHMENT MM – FORM OF PSEUDO-TIE AGREEMENT – WITH NATIVE BA AS PARTY**

**ATTACHMENT MM-1 – FORM OF SYSTEM MODIFICATION COST REIMBURSEMENT AGREEMENT – PSEUDO-TIE INTO PJM**

**ATTACHMENT NN – FORM OF PSEUDO-TIE AGREEMENT WITHOUT NATIVE BA AS PARTY**

**ATTACHMENT OO – FORM OF DYNAMIC SCHEDULE AGREEMENT INTO THE PJM REGION**

**ATTACHMENT PP – FORM OF FIRM TRANSMISSION FEASIBILITY STUDY AGREEMENT**

## **Definitions – A - B**

### **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.

### **Additional Day-ahead Scheduling Reserves Requirement:**

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

### **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” 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 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 Resource Price Adder:**

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

**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, 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 ~~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 Demand Resource Price Decrement:**

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

**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 Capacity Resource Price Decrement:**

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

#### **Base Day-ahead Scheduling Reserves Requirement:**

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

#### **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 Demand Resource:**

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

**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.

**Breach:**

“Breach” shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or 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 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.

## **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 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 hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

**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.

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

**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.

**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, or Operating Agreement, Schedule 1, 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.

**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.

**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.

**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.

**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 used by 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 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 the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

**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 Score:**

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

**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, subpart A.

**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, ~~and~~ 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, ~~and~~ 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 Scheduling Reserves:**

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

**Day-ahead Scheduling Reserves Market:**

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

**Day-ahead Scheduling Reserves Requirement:**

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

**Day-ahead Scheduling Reserves Resources:**

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

**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 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.

**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.

**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 – L – M – N**

### **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.

**Limited Resource Price Decrement:**

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

**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 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 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 units, 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 Regulation or Tier 2 Synchronized 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 units, the LOC Deviation shall

mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output 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 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.

**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.

**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, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant 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 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 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 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 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, and the last generator breaker opening as measured by PJM's State Estimator.

**MISO:**

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

**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.

**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) 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 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 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 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 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 Service Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on April 30 and October 31 of each year shall collectively comprise a New Services Queue.

**New Services Queue Closing Date:**

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the six-month period ending on such date.

**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 create the starting point of a monotonically increasing incremental offer curve for a generating unit.

**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-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.

### **SCHEDULE 9-3**

#### **Market Support Service**

- a) Market Support Service comprises all of the activities of PJM associated with supporting the operation of the PJM Interchange Energy Market and related functions, as described in Operating Agreement, Schedule 1 and Tariff, Attachment K-Appendix, including, but not limited to, market modeling and scheduling functions, locational marginal pricing support, and support of PJM's Internet-based customer transaction tools. PJM provides this service to customers using Point-to-Point or Network Integration Transmission Service under the Tariff, to Generation Providers, as defined below, and to entities that submit offers to sell or bids to buy energy in the PJM Interchange Energy Market.
- b) PJM will charge each user of Market Support Service each month a charge equal to the sum of: (i) the MS Service Rate, Component 1, as stated below, times (1) the total quantity in MWhs of energy delivered to load (including losses and net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region or for export from such region during such month by such user as a customer under Point-to-Point Transmission Service (other than Wheeling-Through Service, as defined below) or Network Integration Transmission Service, plus (2) the total quantity in MWhs of energy input into the Transmission System during such month by such user as a Generation Provider, as defined below, plus (3) the total quantity in MWhs of all accepted Increment Offers and accepted Decrement Bids, and all accepted "Up-to" Congestion Transactions submitted pursuant to Tariff, Attachment K-Appendix, section 1.10.1A(c), submitted by such user during such month; plus (ii) the MS Service Rate Component 2, as stated below, times the number of Bid/Offer Segments, as defined below, submitted by such user during such month. For purposes of this Schedule 9-3, Wheeling-Through Service is Point-to-Point Transmission Service for which both the Point of Receipt and the Point of Delivery are at interconnections of the PJM Region with other Control Areas.
- c) For purposes of this Schedule 9-3, a Generation Provider shall be: (i) a Generation Owner, as such term is defined in the Operating Agreement; provided, however, that if a Generation Owner is not the entity credited on PJM's records for the energy input into the Transmission System from the generation facilities owned or leased (with rights equivalent to ownership) by such Generation Owner, as, for example, in the case of a qualifying facility selling energy to a public utility pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978, then, with respect to such energy, the Generation Provider shall be the entity credited on PJM's records for the energy input into the Transmission System from such generation facilities; (ii) a Network Customer or Point-to-Point Transmission Service customer, with respect to energy arranged by such customer to be delivered for import into the PJM Region; or (iii) a Market Seller with respect to energy arranged by such Market Seller to be delivered for import to the boundaries of the PJM Region and for which there is no separately identifiable Transmission Customer. As the term is used in this Schedule 9-3, energy "credited on PJM's records" does not necessarily mean that a monetary credit resulted on any billing statement provided by PJM.
- d) For purposes of this Schedule 9-3, a Bid/Offer Segment shall be each price/quantity pair submitted into the Day-ahead Energy Market, including those submitted in the generation rebidding period pursuant to Tariff, Attachment K-Appendix, section 1.10.9(a). Segments shall

be hourly for each bid to purchase energy, each Increment Offer, each Decrement Bid, ~~and~~ each “Up-to” Congestion Transaction, and each Day-ahead Pseudo-Tie Transaction. Segments shall be daily for each offer to sell other than an Increment Offer. Each “Up-to” Congestion Transaction also shall be considered a Bid/Offer Segment.

e) The MS Service Rate, Component 1 shall be as follows:

Commencing January 1, 2017:	\$0.0463 per MWh
Commencing January 1, 2019:	\$0.0475 per MWh
Commencing January 1, 2020:	\$0.0487 per MWh
Commencing January 1, 2021:	\$0.0499 per MWh
Commencing January 1, 2022:	\$0.0511 per MWh
Commencing January 1, 2023:	\$0.0524 per MWh
Commencing January 1, 2024:	\$0.0527 per MWh

Users charged the MS Service Rate, Component 1, shall receive a credit in the amount the user is charged the PJMSettlement Market Service Rate set forth in Schedule 9-PJMSettlement during the same billing period.

f) The MS Service Rate, Component 2 shall be as follows:

Commencing January 1, 2017:	\$0.0693 per Bid/Offer Segment
Commencing January 1, 2019:	\$0.0710 per Bid/Offer Segment
Commencing January 1, 2020:	\$0.0728 per Bid/Offer Segment
Commencing January 1, 2021:	\$0.0746 per Bid/Offer Segment
Commencing January 1, 2022:	\$0.0765 per Bid/Offer Segment
Commencing January 1, 2023:	\$0.0784 per Bid/Offer Segment
Commencing January 1, 2024:	\$0.0789 per Bid/Offer Segment

## **1.10 Scheduling.**

### **1.10.1 General.**

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

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

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

#### **1.10.1A Day-ahead Energy Market Scheduling.**

The following actions shall occur not later than 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the

Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

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

(c-2) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock

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

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.
- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's

Offer Data specification, Operating Agreement Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;
- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of



the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

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

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

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

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

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

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

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

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

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

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

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

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

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each

clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

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

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

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead

Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

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

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

### **1.10.1B Demand Bid Scheduling and Screening**

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

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

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

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.

2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

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

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

### **1.10.2 Pool-scheduled Resources.**

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

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

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

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

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

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

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

### **1.10.3 Self-scheduled Resources.**

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

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

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

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

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

#### **1.10.4 Capacity Resources.**

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

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

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

#### **1.10.5 External Resources.**

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

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

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

#### **1.10.6 External Market Buyers.**

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

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

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

#### **1.10.6A Transmission Loading Relief Customers.**

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 10:30 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy



schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

#### **1.10.7 Bilateral Transactions.**

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

#### **1.10.8 Office of the Interconnection Responsibilities.**

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated

flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

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

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

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

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

#### **1.10.9 Hourly Scheduling.**

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable

Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

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

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

#### **1.10.9A Updating Offers in Real-time**

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

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

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

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

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

### **1.10.9B Offer Parameter Flexibility**

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

period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

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

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

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

### **3.8 Market-to-Market Coordination**

The Office of the Interconnection shall charge or credit a Market Participant for the transmission congestion from the Market Participant's Pseudo-Tie generator within MISO to the PJM-MISO interface resulting from market-to-market coordination pursuant to this Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8. The Office of the Interconnection shall calculate such charges and credits for the Real-time Energy Market for each Pseudo-Tie generator using the following formulas.

$$RT\ Charge / Credit_{PT} = RT\ CLMP_{PT} * DevMW_{PT}$$

Where:

$$RTCLMP_{PT} = \sum RT\ ShadowPrice_{FG} * (RT\ ShiftFactor_{FG,PT} - RT\ ShiftFactor_{FG,Interface})$$

$RTCLMP_{PT} =$  Real-time congestion LMP for the path from the Pseudo-Tie generator to the MISO-PJM common interface.

$RT\ ShadowPrice_{FG} =$  Real-time shadow price for each M2M Flowgate calculated in accordance with the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

$RT\ ShiftFactor_{FG,PT} =$  Real-time shift factor for the Pseudo-Tie generator and each M2M Flowgate.

Where:

$$DevMW_{PT} = (RT\ MW_{PT} - DA\ MW_{PT})$$

$DevMW_{PT} =$  The megawatt deviation between the cleared megawatts in the Day-ahead Energy Market and Real-time Energy Market megawatt output for a Pseudo-Tie generator.

$RT\ MW_{PT} =$  Real-time Energy Market megawatt output for the Pseudo-Tie generator.

$DA\ MW_{PT} =$  Cleared and committed megawatts for a Pseudo-Tie generator in the Day-ahead Energy Market.

The dollars refunded to or collected from the Pseudo-Tie generator will be, respectively, distributed from or added to the Balancing Congestion Charges fund.



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

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**OPERATING AGREEMENT  
TABLE OF CONTENTS**

1. DEFINITIONS
  - OA Definitions - A - B
  - OA Definitions - C - D
  - OA Definitions - E - F
  - OA Definitions - G - H
  - OA Definitions - I - L
  - OA Definitions - M - N
  - OA Definitions - O - P
  - OA Definitions - Q - R
  - OA Definitions - S - T
  - OA Definitions - U - Z
2. FORMATION, NAME; PLACE OF BUSINESS
  - 2.1 Formation of LLC; Certificate of Formation
  - 2.2 Name of LLC
  - 2.3 Place of Business
  - 2.4 Registered Office and Registered Agent
3. PURPOSES AND POWERS OF LLC
  - 3.1 Purposes
  - 3.2 Powers
4. EFFECTIVE DATE AND TERMINATION
  - 4.1 Effective Date and Termination
  - 4.2 Governing Law
5. WORKING CAPITAL AND CAPITAL CONTRIBUTIONS
  - 5.1 Funding of Working Capital and Capital Contributions
  - 5.2 Contributions to Association
6. TAX STATUS AND DISTRIBUTIONS
  - 6.1 Tax Status
  - 6.2 Return of Capital Contributions
  - 6.3 Liquidating Distribution
7. PJM BOARD
  - 7.1 Composition
  - 7.2 Qualifications
  - 7.3 Term of Office
  - 7.4 Quorum
  - 7.5 Operating and Capital Budgets
  - 7.6 By-laws
  - 7.7 Duties and Responsibilities of the PJM Board
8. MEMBERS COMMITTEE
  - 8.1 Sectors
  - 8.2 Representatives
  - 8.3 Meetings

- 8.4 Manner of Acting
- 8.5 Chair and Vice Chair of the Members Committee
- 8.6 Senior, Standing, and Other Committees
- 8.7 User Groups
- 8.8 Powers of the Members Committee
- 9. OFFICERS
  - 9.1 Election and Term
  - 9.2 President
  - 9.3 Secretary
  - 9.4 Treasurer
  - 9.5 Renewal of Officers; Vacancies
  - 9.6 Compensation
- 10. OFFICE OF THE INTERCONNECTION
  - 10.1 Establishment
  - 10.2 Processes and Organization
    - 10.2.1 Financial Interests
  - 10.3 Confidential Information
  - 10.4 Duties and Responsibilities
- 11. MEMBERS
  - 11.1 Management Rights
  - 11.2 Other Activities
  - 11.3 Member Responsibilities
  - 11.4 Regional Transmission Expansion Planning Protocol
  - 11.5 Member Right to Petition
  - 11.6 Membership Requirements
  - 11.7 Associate Membership Requirements
- 12. TRANSFERS OF MEMBERSHIP INTEREST
- 13. INTERCHANGE
  - 13.1 Interchange Arrangements with Non-Members
  - 13.2 Energy Market
- 14. METERING
  - 14.1 Installation, Maintenance and Reading of Meters
  - 14.2 Metering Procedures
  - 14.3 Integrated Megawatt-Hours
  - 14.4 Meter Locations
  - 14.5 Metering of Behind The Meter Generation
- 14A. TRANSMISSION LOSSES
  - 14A.1 Description of Transmission Losses
  - 14A.2 Inclusion of State Estimator Transmission Losses
  - 14A.3 Other Losses
- 15. ENFORCEMENT OF OBLIGATIONS
  - 15.1 Failure to Meet Obligations
  - 15.2 Enforcement of Obligations
  - 15.3 Obligations to a Member in Default
  - 15.4 Obligations of a Member in Default
  - 15.5 No Implied Waiver

- 15.6 Limitation on Claims
- 16. LIABILITY AND INDEMNITY
  - 16.1 Members
  - 16.2 LLC Indemnified Parties
  - 16.3 Workers Compensation Claims
  - 16.4 Limitation of Liability
  - 16.5 Resolution of Disputes
  - 16.6 Gross Negligence or Willful Misconduct
  - 16.7 Insurance
- 17. MEMBER REPRESENTATIONS, WARRANTIES AND COVENANTS
  - 17.1 Representations and Warranties
  - 17.2 Municipal Electric Systems
  - 17.3 Survival
- 18. MISCELLANEOUS PROVISIONS
  - 18.1 [Reserved.]
  - 18.2 Fiscal and Taxable Year
  - 18.3 Reports
  - 18.4 Bank Accounts; Checks, Notes and Drafts
  - 18.5 Books and Records
  - 18.6 Amendment
  - 18.7 Interpretation
  - 18.8 Severability
  - 18.9 Catastrophic Force Majeure
  - 18.10 Further Assurances
  - 18.11 Seal
  - 18.12 Counterparts
  - 18.13 Costs of Meetings
  - 18.14 Notice
  - 18.15 Headings
  - 18.16 No Third-Party Beneficiaries
  - 18.17 Confidentiality
  - 18.18 Termination and Withdrawal
    - 18.18.1 Termination
    - 18.18.2 Withdrawal
    - 18.18.3 Winding Up

#### RESOLUTION REGARDING ELECTION OF DIRECTORS

#### SCHEDULE 1 – PJM INTERCHANGE ENERGY MARKET

- 1. MARKET OPERATIONS
  - 1.1 Introduction
  - 1.2 Cost-Based Offers
  - 1.2A Transmission Losses
  - 1.3 [Reserved for Future Use]
  - 1.4 Market Buyers
  - 1.5 Market Sellers
  - 1.5A Economic Load Response Participant
  - 1.6 Office of the Interconnection

- 1.6A PJMSettlement
- 1.7 General
- 1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process
- 1.9 Prescheduling
- 1.10 Scheduling
- 1.11 Dispatch
- 1.12 Dynamic Transfers
- 2. CALCULATION OF LOCATIONAL MARGINAL PRICES
  - 2.1 Introduction
  - 2.2 General
  - 2.3 Determination of System Conditions Using the State Estimator
  - 2.4 Determination of Energy Offers Used in Calculating Real-time Prices
  - 2.5 Calculation of Real-time Prices
  - 2.6 Calculation of Day-ahead Prices
  - 2.6A Interface Prices
  - 2.7 Performance Evaluation
- 3. ACCOUNTING AND BILLING
  - 3.1 Introduction
  - 3.2 Market Buyers
  - 3.3 Market Sellers
  - 3.3A Economic Load Response Participants
  - 3.4 Transmission Customers
  - 3.5 Other Control Areas
  - 3.6 Metering Reconciliation
  - 3.7 Inadvertent Interchange
  - 3.8 Market-to-Market Coordination
- 4. [Reserved For Future Use]
- 5. CALCULATION OF CHARGES AND CREDITS FOR TRANSMISSION CONGESTION AND LOSSES
  - 5.1 Transmission Congestion Charge Calculation
  - 5.2 Transmission Congestion Credit Calculation
  - 5.3 Unscheduled Transmission Service (Loop Flow)
  - 5.4 Transmission Loss Charge Calculation
  - 5.5 Distribution of Total Transmission Loss Charges
- 6. “MUST-RUN” FOR RELIABILITY GENERATION
  - 6.1 Introduction
  - 6.2 Identification of Facility Outages
  - 6.3 Dispatch for Local Reliability
  - 6.4 Offer Price Caps
  - 6.5 [Reserved]
  - 6.6 Minimum Generator Operating Parameters – Parameter-Limited Schedules
- 6A [Reserved]
  - 6A.1 [Reserved]
  - 6A.2 [Reserved]
  - 6A.3 [Reserved]
- 7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS

- 7.1 Auctions of Financial Transmission Rights
- 7.1A Long-Term Financial Transmission Rights Auctions
- 7.2 Financial Transmission Rights Characteristics
- 7.3 Auction Procedures
- 7.4 Allocation of Auction Revenues
- 7.5 Simultaneous Feasibility
- 7.6 New Stage 1 Resources
- 7.7 Alternate Stage 1 Resources
- 7.8 Elective Upgrade Auction Revenue Rights
- 7.9 Residual Auction Revenue Rights
- 7.10 Financial Settlement
- 7.11 PJM Settlement as Counterparty
- 8. EMERGENCY AND PRE-EMERGENCY LOAD RESPONSE PROGRAM
  - 8.1 Emergency Load Response and Pre-Emergency Load Response Program Options
  - 8.2 Participant Qualifications
  - 8.3 Metering Requirements
  - 8.4 Registration
  - 8.5 Pre-Emergency Operations
  - 8.6 Emergency Operations
  - 8.7 Verification
  - 8.8 Market Settlements
  - 8.9 Reporting and Compliance
  - 8.10 Non-Hourly Metered Customer Pilot
  - 8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation
- SCHEDULE 2 – COMPONENTS OF COST
- SCHEDULE 2 –EXHIBIT A, EXPLANATION OF THE TREATMENT OF THE COSTS OF EMISSION ALLOWANCES
- SCHEDULE 3 –ALLOCATION OF THE COST AND EXPENSES OF THE OFFICE OF THE INTERCONNECTION
- SCHEDULE 4 –STANDARD FORM OF AGREEMENT TO BECOME A MEMBER OF THE LLC
- SCHEDULE 5 –PJM DISPUTE RESOLUTION PROCEDURES
  - 1. DEFINITIONS
    - 1.1 Alternate Dispute Resolution Committee
    - 1.2 MAAC Dispute Resolution Committee
    - 1.3 Related PJM Agreements
  - 2. PURPOSES AND OBJECTIVES
    - 2.1 Common and Uniform Procedures
    - 2.2 Interpretation
  - 3. NEGOTIATION AND MEDIATION
    - 3.1 When Required
    - 3.2 Procedures
    - 3.3 Costs
  - 4. ARBITRATION
    - 4.1 When Required

- 4.2 Binding Decision
  - 4.3 Initiation
  - 4.4 Selection of Arbitrator(s)
  - 4.5 Procedures
  - 4.6 Summary Disposition and Interim Measures
  - 4.7 Discovery of Facts
  - 4.8 Evidentiary Hearing
  - 4.9 Confidentiality
  - 4.10 Timetable
  - 4.11 Advisory Interpretations
  - 4.12 Decisions
  - 4.13 Costs
  - 4.14 Enforcement
  - 5. ALTERNATE DISPUTE RESOLUTION COMMITTEE
    - 5.1 Membership
    - 5.2 Voting Requirements
    - 5.3 Officers
    - 5.4 Meetings
    - 5.5 Responsibilities
- SCHEDULE 6 – REGIONAL TRANSMISSION EXPANSION  
PLANNING PROTOCOL
- 1. REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL
    - 1.1 Purpose and Objectives
    - 1.2 Conformity with NERC and Other Applicable Criteria
    - 1.3 Establishment of Committees
    - 1.4 Contents of the Regional Transmission Expansion Plan
    - 1.5 Procedure for Development of the Regional Transmission Expansion Plan
    - 1.6 Approval of the Final Regional Transmission Expansion Plan
    - 1.7 Obligation to Build
    - 1.8 Interregional Expansions
    - 1.9 Relationship to the PJM Open Access Transmission Tariff
- SCHEDULE 7 – UNDERFREQUENCY RELAY OBLIGATIONS AND CHARGES
- 1. UNDERFREQUENCY RELAY OBLIGATION
    - 1.1 Application
    - 1.2 Obligations
  - 2. UNDERFREQUENCY RELAY CHARGES
  - 3. DISTRIBUTION OF UNDERFREQUENCY RELAY CHARGES
    - 3.1 Share of Charges
    - 3.2 Allocation by the Office of the Interconnection
- SCHEDULE 8 – DELEGATION OF PJM CONTROL AREA RELIABILITY  
RESPONSIBILITIES
- 1. DELEGATION
  - 2. NEW PARTIES
  - 3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT
- SCHEDULE 9B – PJM SOUTH REGION EMERGENCY PROCEDURE CHARGES
- 1. EMERGENCY PROCEDURE CHARGE

## 2. DISTRIBUTION OF EMERGENCY PROCEDURE CHARGES

2.1 Complying Parties

2.2 All Parties

## SCHEDULE 10 – FORM OF NON-DISCLOSURE AGREEMENT

### 1. DEFINITIONS

1.1 Affected Member

1.2 Authorized Commission

1.3 Authorized Person

1.4 Confidential Information

1.5 FERC

1.6 Information Request.

1.7 Operating Agreement

1.8 Market Monitoring Unit

1.9 PJM Tariff

1.10 Third Party Request.

### 2. Protection of Confidentiality

2.1 Duty to Not Disclose

2.2 Discussion of Confidential Information with Other Authorized Persons

2.3 Defense Against Third Party Requests

2.4 Care and Use of Confidential Information

2.5 Ownership and Privilege

### 3. Remedies

3.1 Material Breach

3.2 Judicial Recourse

3.3 Waiver of Monetary Damages

### 4. Jurisdiction

### 5. Notices

### 6. Severability and Survival

### 7. Representations

### 8. Third Party Beneficiaries

### 9. Counterparts

### 10. Amendment

## SCHEDULE 10A – FORM OF CERTIFICATION

### 1. Definitions

### 2. Requisite Authority

### 3. Protection of Confidential Information

### 4. Defense Against Requests for Disclosure

### 5. Use and Destruction of Confidential Information

### 6. Notice of Disclosure of Confidential Information

### 7. Release of Claims

### 8. Ownership and Privilege

Exhibit A - Certification List of Authorized Persons

## SCHEDULE 11 – ALLOCATION OF COSTS ASSOCIATED WITH NERC

## PENALTY ASSESSMENTS

### 1.1 Purpose and Objectives

### 1.2 Definitions



- 1.3 Allocation of Costs When PJM is the Registered Entity
- 1.4 Allocation of Costs When a PJM Member is the Registered Entity
- 1.5

**SCHEDULE 12 – PJM MEMBER LIST**

**RESOLUTION TO AMEND THE PROCEDURES REQUIRING THE RETENTION OF AN INDEPENDENT CONSULTANT TO PROPOSE A LIST OF CANDIDATES FOR THE BOARD OF MANAGERS ELECTION FOR 2001**

## **Definitions A - B**

### **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, 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 and Tariff, Attachment K-Appendix, section 1.9.4.

### **Act:**

“Act” shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

### **Active and Significant Business Interest:**

“Active and Significant Business Interest” is a term that shall be used to assess the scope of a Member’s PJM membership and shall be based on a Member’s activity in the PJM RTO and/or Interchange Energy Markets. A Member’s Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member’s PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member’s public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member’s recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates’ interests within the PJM footprint.

### **Additional Day-ahead Scheduling Reserves Requirement:**

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

### **Affected Member:**

“Affected Member” shall mean a Member of PJM which as a result of its participation in PJM’s markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

### **Affiliate:**

“Affiliate” shall mean any two or more entities, one of which controls the other or that are under common control. “Control” 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 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.

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

“Agreement,” “Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean this 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 thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

**Annual Meeting of the Members:**

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

**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.

**Associate Member:**

“Associate Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.7.

**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 Commission:**

“Authorized Commission” shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

**Authorized Person:**

“Authorized Person” shall have the meaning set forth in Operating Agreement, section 18.17.4.

**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 ~~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)].

**Base Day-ahead Scheduling Reserves Requirement:**

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

**Batch Load Demand Resource:**

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

**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 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 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.

**Board Member:**

“Board Member” shall mean a member of the PJM Board.

## **Definitions C - D**

### **Capacity Resource:**

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

### **Catastrophic Force Majeure:**

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

### **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.

**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, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

**Compliance Monitoring and Enforcement Program:**

“Compliance Monitoring and Enforcement Program” shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

**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 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 automatic generation control scheme is applied in order to:

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

**Control Zone:**

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

**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.

**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 this 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 extent that energy serves that Member’s own load.

**Credit Breach:**



“Credit Breach” is the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

**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 Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45). 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.

**Curtailed Service Provider:**

“Curtailed 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.

**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, ~~and~~-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, ~~and~~-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 Scheduling Reserves:**

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

**Day-ahead Scheduling Reserves Market:**

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

**Day-ahead Scheduling Reserves Requirement:**

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

**Day-ahead Scheduling Reserves Resources:**

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

**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.

**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 Allocation Assessment:**

“Default Allocation Assessment” shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

**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 have the meaning provided in the Reliability Assurance Agreement.

**Designated Entity:**

“Designated Entity” shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

**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.

**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.

**Dynamic Schedule:**

“Dynamic Schedule” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

**Dynamic Transfer:**

“Dynamic Transfer” shall mean a Pseudo-Tie or Dynamic Schedule.

## Definitions M - N

### **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.

### **Market Buyer:**

“Market Buyer” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make purchases in the PJM Interchange Energy Market.

### **Market Monitoring Unit or MMU:**

“Market Monitoring Unit” or “MMU” shall mean 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 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, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant 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 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 Seller:**

“Market Seller” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make sales in the PJM Interchange Energy Market.

**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 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 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 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 mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Operating Agreement, Schedule 4.

**Members Committee:**

“Members Committee” shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

**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 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 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, and the last generator breaker opening as measured by PJM’s State Estimator.

**MISO:**

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

**Multi-Driver Project:**

“Multi-Driver Project” shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

**NERC:**

“NERC” shall mean the North American Electric Reliability Corporation, or any successor thereto.

**NERC Functional Model:**

“NERC Functional Model” shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

**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.

**NERC Reliability Standards:**

“NERC Reliability Standards” shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.



**NERC Rules of Procedure:**“NERC Rules of Procedure” shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

**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.

**Network Resource:**

“Network Resource” shall have the meaning specified in the PJM Tariff.

**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.

**New York ISO or NYISO:**

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

**No-load Cost:**

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

**Non-Disclosure Agreement:**

“Non-Disclosure Agreement” shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Operating Agreement, section, the form of which is appended to this Agreement as Operating Agreement, Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

**Nonincumbent Developer:**

“Nonincumbent Developer” shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J.

**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, and 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, 1.5A.6.

**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.

## **1.10 Scheduling.**

### **1.10.1 General.**

- (a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.
- (b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.
- (c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.
- (d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

#### **1.10.1A Day-ahead Energy Market Scheduling.**

The following actions shall occur not later than 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection:

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified

in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

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

(c-2) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the

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

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.
- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional,

but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d), and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;
- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour,



or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour; and
- ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant, an Emergency Load Response participant, or a Pre-Emergency Load Response participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour; and
- x) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

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

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and
- iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

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

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

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

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

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance

problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

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

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Demand Resource. The submission of demand reduction bids for Demand Resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. A Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead

Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Demand Resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

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

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

#### **1.10.1B Demand Bid Scheduling and Screening**

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

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids

submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

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

Where:

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

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

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

### **1.10.2 Pool-scheduled Resources.**

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in

Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

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

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

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

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

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

### **1.10.3 Self-scheduled Resources.**

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

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

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

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

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

#### **1.10.4 Capacity Resources.**

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

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

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

#### **1.10.5 External Resources.**

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall

be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

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

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

#### **1.10.6 External Market Buyers.**

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

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

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

#### **1.10.6A Transmission Loading Relief Customers.**

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:



- (i) enter its election on OASIS by 10:30 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and
- (ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

#### **1.10.7 Bilateral Transactions.**

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

#### **1.10.8 Office of the Interconnection Responsibilities.**

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv)

the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

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

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection

(b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

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

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

#### **1.10.9 Hourly Scheduling.**

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the

results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

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

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

External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

#### **1.10.9A Updating Offers in Real-time**

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

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

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

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

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

### **1.10.9B Offer Parameter Flexibility**

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

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

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

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

### **3.8 Market-to-Market Coordination**

The Office of the Interconnection shall charge or credit a Market Participant for the transmission congestion from the Market Participant's Pseudo-Tie generator within MISO to the PJM-MISO interface resulting from market-to-market coordination pursuant to this Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8. The Office of the Interconnection shall calculate such charges and credits for the Real-time Energy Market for each Pseudo-Tie generator using the following formulas.

$$RT Charge / Credit_{PT} = RT CLMP_{PT} * DevMW_{PT}$$

Where:

$$RTCLMP_{PT} = \sum RT ShadowPrice_{FG} * (RT ShiftFactor_{FG,PT} - RT ShiftFactor_{FG,Interface})$$

<u>RTCLMP<sub>PT</sub> =</u>	<u>Real-time congestion LMP for the path from the Pseudo-Tie generator to the MISO-PJM common interface.</u>
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<u>RT ShadowPrice<sub>FG</sub> =</u>	<u>Real-time shadow price for each M2M Flowgate calculated in accordance with the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.</u>
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<u>RT ShiftFactor<sub>FG,PT</sub> =</u>	<u>Real-time shift factor for the Pseudo-Tie generator and each M2M Flowgate.</u>
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Where:

$$DevMW_{PT} = (RT MW_{PT} - DA MW_{PT})$$

<u>DevMW<sub>PT</sub> =</u>	<u>The megawatt deviation between the cleared megawatts in the Day-ahead Energy Market and Real-time Energy Market megawatt output for a Pseudo-Tie generator.</u>
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<u>RT MW<sub>PT</sub> =</u>	<u>Real-time Energy Market megawatt output for the Pseudo-Tie generator.</u>
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<u>DA MW<sub>PT</sub> =</u>	<u>Cleared and committed megawatts for a Pseudo-Tie generator in the Day-ahead Energy Market.</u>
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The dollars refunded to or collected from the Pseudo-Tie generator will be, respectively, distributed from or added to the Balancing Congestion Charges fund.



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

Section(s) of the  
PJM Operating Agreement  
(Clean Format)

## **TABLE OF CONTENTS**

### **I. COMMON SERVICE PROVISIONS**

- 1 Definitions**
  - OATT Definitions – A – B**
  - OATT Definitions – C – D**
  - OATT Definitions – E – F**
  - OATT Definitions – G – H**
  - OATT Definitions – I – J – K**
  - OATT Definitions – L – M – N**
  - OATT Definitions – O – P – Q**
  - OATT Definitions – R – S**
  - OATT Definitions – T – U – V**
  - OATT Definitions – W – X – Y – Z**
- 2 Initial Allocation and Renewal Procedures**
- 3 Ancillary Services**
- 3B PJM Administrative Service**
- 3C Mid-Atlantic Area Council Charge**
- 3D Transitional Market Expansion Charge**
- 3E Transmission Enhancement Charges**
- 3F Transmission Losses**
- 4 Open Access Same-Time Information System (OASIS)**
- 5 Local Furnishing Bonds**
- 6 Reciprocity**
- 6A Counterparty**
- 7 Billing and Payment**
- 8 Accounting for a Transmission Owner's Use of the Tariff**
- 9 Regulatory Filings**
- 10 Force Majeure and Indemnification**
- 11 Creditworthiness**
- 12 Dispute Resolution Procedures**
- 12A PJM Compliance Review**

### **II. POINT-TO-POINT TRANSMISSION SERVICE**

#### **Preamble**

- 13 Nature of Firm Point-To-Point Transmission Service**
- 14 Nature of Non-Firm Point-To-Point Transmission Service**
- 15 Service Availability**
- 16 Transmission Customer Responsibilities**
- 17 Procedures for Arranging Firm Point-To-Point Transmission Service**
- 18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service**
- 19 Firm Transmission Feasibility Study Procedures For Long-Term Firm Point-To-Point Transmission Service Requests**
- 20 [Reserved]**

- 21 [Reserved]
- 22 Changes in Service Specifications
- 23 Sale or Assignment of Transmission Service
- 24 Metering and Power Factor Correction at Receipt and Delivery Points(s)
- 25 Compensation for Transmission Service
- 26 Stranded Cost Recovery
- 27 Compensation for New Facilities and Redispatch Costs
- 27A Distribution of Revenues from Non-Firm Point-to-Point Transmission Service

### **III. NETWORK INTEGRATION TRANSMISSION SERVICE**

#### **Preamble**

- 28 Nature of Network Integration Transmission Service
- 29 Initiating Service
- 30 Network Resources
- 31 Designation of Network Load
- 32 Firm Transmission Feasibility Study Procedures For Network Integration Transmission Service Requests
- 33 Load Shedding and Curtailments
- 34 Rates and Charges
- 35 Operating Arrangements

### **IV. INTERCONNECTIONS WITH THE TRANSMISSION SYSTEM**

#### **Preamble**

#### **Subpart A –INTERCONNECTION PROCEDURES**

- 36 Interconnection Requests
- 37 Additional Procedures
- 38 Service on Merchant Transmission Facilities
- 39 Local Furnishing Bonds

40-108 [Reserved]

Subpart B – [Reserved]

Subpart C – [Reserved]

Subpart D – [Reserved]

Subpart E – [Reserved]

Subpart F – [Reserved]

#### **Subpart G – SMALL GENERATION INTERCONNECTION PROCEDURE**

#### **Preamble**

- 109 Pre-application Process
- 110 Permanent Capacity Resource Additions Of 20 MW Or Less
- 111 Permanent Energy Resource Additions Of 20 MW Or Less but Greater than 2 MW (Synchronous) or Greater than 5 MW(Inverter-based)
- 112 Temporary Energy Resource Additions Of 20 MW Or Less But Greater Than 2 MW
- 112A Screens Process for Permanent or Temporary Energy Resources of 2 MW or less (Synchronous) or 5 MW (Inverter-based)

- 112B Certified Inverter-Based Small Generating Facilities No Larger than 10 kW
- 112C [Reserved]

**V. GENERATION DEACTIVATION**

**Preamble**

- 113 Notices
- 114 Deactivation Avoidable Cost Credit
- 115 Deactivation Avoidable Cost Rate
- 116 Filing and Updating of Deactivation Avoidable Cost Rate
  - 117 Excess Project Investment Required
  - 118 Refund of Project Investment Reimbursement
  - 118A Recovery of Project Investment
  - 119 Cost of Service Recovery Rate
  - 120 Cost Allocation
  - 121 Performance Standards
  - 122 Black Start Units
  - 123-199 [Reserved]

**VI. ADMINISTRATION AND STUDY OF NEW SERVICE REQUESTS; RIGHTS ASSOCIATED WITH CUSTOMER-FUNDED UPGRADES**

**Preamble**

- 200 Applicability
- 201 Queue Position
  - Subpart A – SYSTEM IMPACT STUDIES AND FACILITIES STUDIES FOR NEW SERVICE REQUESTS
- 202 Coordination with Affected Systems
- 203 System Impact Study Agreement
- 204 Tender of System Impact Study Agreement
- 205 System Impact Study Procedures
- 206 Facilities Study Agreement
- 207 Facilities Study Procedures
- 208 Expedited Procedures for Part II Requests
- 209 Optional Interconnection Studies
- 210 Responsibilities of the Transmission Provider and Transmission Owners
  - Subpart B– AGREEMENTS AND COST REPONSIBILITY FOR CUSTOMER- FUNDED UPGRADES
- 211 Interim Interconnection Service Agreement
- 212 Interconnection Service Agreement
- 213 Upgrade Construction Service Agreement
- 214 Filing/Reporting of Agreement
- 215 Transmission Service Agreements
- 216 Interconnection Requests Designated as Market Solutions
- 217 Cost Responsibility for Necessary Facilities and Upgrades
- 218 New Service Requests Involving Affected Systems
- 219 Inter-queue Allocation of Costs of Transmission Upgrades

- 220 Advance Construction of Certain Network Upgrades**
- 221 Transmission Owner Construction Obligation for Necessary Facilities And Upgrades**
- 222 Confidentiality**
- 223 Confidential Information**
- 224 – 229 [Reserved]**
- Subpart C – RIGHTS RELATED TO CUSTOMER-FUNDED UPGRADES**
- 230 Capacity Interconnection Rights**
- 231 Incremental Auction Revenue Rights**
- 232 Transmission Injection Rights and Transmission Withdrawal Rights**
- 233 Incremental Available Transfer Capability Revenue Rights**
- 234 Incremental Capacity Transfer Rights**
- 235 Incremental Deliverability Rights**
- 236 Interconnection Rights for Certain Transmission Interconnections**
- 237 IDR Transfer Agreements**

#### **SCHEDULE 1**

**Scheduling, System Control and Dispatch Service**

#### **SCHEDULE 1A**

**Transmission Owner Scheduling, System Control and Dispatch Service**

#### **SCHEDULE 2**

**Reactive Supply and Voltage Control from Generation Sources Service**

#### **SCHEDULE 3**

**Regulation and Frequency Response Service**

#### **SCHEDULE 4**

**Energy Imbalance Service**

#### **SCHEDULE 5**

**Operating Reserve – Synchronized Reserve Service**

#### **SCHEDULE 6**

**Operating Reserve - Supplemental Reserve Service**

#### **SCHEDULE 6A**

**Black Start Service**

#### **SCHEDULE 7**

**Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service**

#### **SCHEDULE 8**

**Non-Firm Point-To-Point Transmission Service**

#### **SCHEDULE 9**

**PJM Interconnection L.L.C. Administrative Services**

#### **SCHEDULE 9-1**

**Control Area Administration Service**

#### **SCHEDULE 9-2**

**Financial Transmission Rights Administration Service**

#### **SCHEDULE 9-3**

**Market Support Service**

#### **SCHEDULE 9-4**

**Regulation and Frequency Response Administration Service**  
**SCHEDULE 9-5**  
**Capacity Resource and Obligation Management Service**  
**SCHEDULE 9-6**  
**Management Service Cost**  
**SCHEDULE 9-FERC**  
**FERC Annual Charge Recovery**  
**SCHEDULE 9-OPSI**  
**OPSI Funding**  
**SCHEDULE 9-CAPS**  
**CAPS Funding**  
**SCHEDULE 9-FINCON**  
**Finance Committee Retained Outside Consultant**  
**SCHEDULE 9-MMU**  
**MMU Funding**  
**SCHEDULE 9 – PJM SETTLEMENT**  
**SCHEDULE 10 - [Reserved]**  
**SCHEDULE 10-NERC**  
**North American Electric Reliability Corporation Charge**  
**SCHEDULE 10-RFC**  
**Reliability First Corporation Charge**  
**SCHEDULE 11**  
**[Reserved for Future Use]**  
**SCHEDULE 11A**  
**Additional Secure Control Center Data Communication Links and Formula Rate**  
**SCHEDULE 12**  
**Transmission Enhancement Charges**  
**SCHEDULE 12 APPENDIX**  
**SCHEDULE 12-A**  
**SCHEDULE 13**  
**Expansion Cost Recovery Change (ECRC)**  
**SCHEDULE 14**  
**Transmission Service on the Neptune Line**  
**SCHEDULE 14 - Exhibit A**  
**SCHEDULE 15**  
**Non-Retail Behind The Meter Generation Maximum Generation Emergency Obligations**  
**SCHEDULE 16**  
**Transmission Service on the Linden VFT Facility**  
**SCHEDULE 16 Exhibit A**  
**SCHEDULE 16 – A**  
**Transmission Service for Imports on the Linden VFT Facility**  
**SCHEDULE 17**  
**Transmission Service on the Hudson Line**  
**SCHEDULE 17 - Exhibit A**  
**ATTACHMENT A**

	Form of Service Agreement For Firm Point-To-Point Transmission Service
ATTACHMENT A-1	Form of Service Agreement For The Resale, Reassignment or Transfer of Point-to-Point Transmission Service
ATTACHMENT B	Form of Service Agreement For Non-Firm Point-To-Point Transmission Service
ATTACHMENT C	Methodology To Assess Available Transfer Capability
ATTACHMENT C-1	Conversion of Service in the Dominion and Duquesne Zones
ATTACHMENT C-2	Conversion of Service in the Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc, (“DEOK”) Zone
ATTACHMENT C-4	Conversion of Service in the OVEC Zone
ATTACHMENT D	Methodology for Completing a System Impact Study
ATTACHMENT E	Index of Point-To-Point Transmission Service Customers
ATTACHMENT F	Service Agreement For Network Integration Transmission Service
ATTACHMENT F-1	Form of Umbrella Service Agreement for Network Integration Transmission Service Under State Required Retail Access Programs
ATTACHMENT G	Network Operating Agreement
ATTACHMENT H-1	Annual Transmission Rates -- Atlantic City Electric Company for Network Integration Transmission Service
ATTACHMENT H-1A	Atlantic City Electric Company Formula Rate Appendix A
ATTACHMENT H-1B	Atlantic City Electric Company Formula Rate Implementation Protocols
ATTACHMENT H-2	Annual Transmission Rates -- Baltimore Gas and Electric Company for Network Integration Transmission Service
ATTACHMENT H-2A	Baltimore Gas and Electric Company Formula Rate
ATTACHMENT H-2B	Baltimore Gas and Electric Company Formula Rate Implementation Protocols
ATTACHMENT H-3	Annual Transmission Rates -- Delmarva Power & Light Company for Network Integration Transmission Service
ATTACHMENT H-3A	Delmarva Power & Light Company Load Power Factor Charge Applicable to Service the Interconnection Points



**ATTACHMENT H-3B**

**Delmarva Power & Light Company Load Power Factor Charge Applicable to Service the Interconnection Points**

**ATTACHMENT H-3C**

**Delmarva Power & Light Company Under-Frequency Load Shedding Charge**

**ATTACHMENT H-3D**

**Delmarva Power & Light Company Formula Rate – Appendix A**

**ATTACHMENT H-3E**

**Delmarva Power & Light Company Formula Rate Implementation Protocols**

**ATTACHMENT H-3F**

**Old Dominion Electric Cooperative Formula Rate – Appendix A**

**ATTACHMENT H-3G**

**Old Dominion Electric Cooperative Formula Rate Implementation Protocols**

**ATTACHMENT H-4**

**Annual Transmission Rates -- Jersey Central Power & Light Company for Network Integration Transmission Service**

**ATTACHMENT H-4A**

**Other Supporting Facilities - Jersey Central Power & Light Company**

**ATTACHMENT H-4B**

**Jersey Central Power & Light Company – [Reserved]**

**ATTACHMENT H-5**

**Annual Transmission Rates -- Metropolitan Edison Company for Network Integration Transmission Service**

**ATTACHMENT H-5A**

**Other Supporting Facilities -- Metropolitan Edison Company**

**ATTACHMENT H-6**

**Annual Transmission Rates -- Pennsylvania Electric Company for Network Integration Transmission Service**

**ATTACHMENT H-6A**

**Other Supporting Facilities Charges -- Pennsylvania Electric Company**

**ATTACHMENT H-7**

**Annual Transmission Rates -- PECO Energy Company for Network Integration Transmission Service**

**ATTACHMENT H-7A**

**PECO Energy Company Formula Rate Template**

**ATTACHMENT H-7B**

**PECO Energy Company Monthly Deferred Tax Adjustment Charge**

**ATTACHMENT H-7C**

**PECO Energy Company Formula Rate Implementation Protocols**

**ATTACHMENT H-8**

**Annual Transmission Rates – PPL Group for Network Integration Transmission Service**

**ATTACHMENT H-8A**

**Other Supporting Facilities Charges -- PPL Electric Utilities Corporation**

**ATTACHMENT 8C**

**UGI Utilities, Inc. Formula Rate – Appendix A**

**ATTACHMENT 8D**

**UGI Utilities, Inc. Formula Rate Implementation Protocols**

**ATTACHMENT 8E**

**UGI Utilities, Inc. Formula Rate – Appendix A**

**ATTACHMENT H-8G**

**Annual Transmission Rates – PPL Electric Utilities Corp.**

**ATTACHMENT H-8H**

**Formula Rate Implementation Protocols – PPL Electric Utilities Corp.**

**ATTACHMENT H-9**

**Annual Transmission Rates -- Potomac Electric Power Company for Network Integration Transmission Service**

**ATTACHMENT H-9A**

**Potomac Electric Power Company Formula Rate – Appendix A**

**ATTACHMENT H-9B**

**Potomac Electric Power Company Formula Rate Implementation Protocols**

**ATTACHMENT H-9C**

**Annual Transmission Rate – Southern Maryland Electric Cooperative, Inc. for Network Integration Transmission Service**

**ATTACHMENT H-10**

**Annual Transmission Rates -- Public Service Electric and Gas Company for Network Integration Transmission Service**

**ATTACHMENT H-10A**

**Formula Rate -- Public Service Electric and Gas Company**

**ATTACHMENT H-10B**

**Formula Rate Implementation Protocols – Public Service Electric and Gas Company**

**ATTACHMENT H-11**

**Annual Transmission Rates -- Allegheny Power for Network Integration Transmission Service**

**ATTACHMENT 11A**

**Other Supporting Facilities Charges - Allegheny Power**

**ATTACHMENT H-12**

**Annual Transmission Rates -- Rockland Electric Company for Network Integration Transmission Service**

**ATTACHMENT H-13**

**Annual Transmission Rates – Commonwealth Edison Company for Network Integration Transmission Service**

**ATTACHMENT H-13A**

**Commonwealth Edison Company Formula Rate – Appendix A**

**ATTACHMENT H-13B**

**Commonwealth Edison Company Formula Rate Implementation Protocols**

**ATTACHMENT H-14**

**Annual Transmission Rates – AEP East Operating Companies for Network Integration Transmission Service**

**ATTACHMENT H-14A**

**AEP East Operating Companies Formula Rate Implementation Protocols**

**ATTACHMENT H-14B Part 1**

**ATTACHMENT H-14B Part 2**

**ATTACHMENT H-15**

**Annual Transmission Rates -- The Dayton Power and Light Company  
for Network Integration Transmission Service**

**ATTACHMENT H-16**

**Annual Transmission Rates -- Virginia Electric and Power Company  
for Network Integration Transmission Service**

**ATTACHMENT H-16A**

**Formula Rate - Virginia Electric and Power Company**

**ATTACHMENT H-16B**

**Formula Rate Implementation Protocols - Virginia Electric and Power Company**

**ATTACHMENT H-16C**

**Virginia Retail Administrative Fee Credit for Virginia Retail Load Serving  
Entities in the Dominion Zone**

**ATTACHMENT H-16D – [Reserved]**

**ATTACHMENT H-16E – [Reserved]**

**ATTACHMENT H-16AA**

**Virginia Electric and Power Company**

**ATTACHMENT H-17**

**Annual Transmission Rates -- Duquesne Light Company for Network Integration  
Transmission Service**

**ATTACHMENT H-17A**

**Duquesne Light Company Formula Rate – Appendix A**

**ATTACHMENT H-17B**

**Duquesne Light Company Formula Rate Implementation Protocols**

**ATTACHMENT H-17C**

**Duquesne Light Company Monthly Deferred Tax Adjustment Charge**

**ATTACHMENT H-18**

**Annual Transmission Rates – Trans-Allegheny Interstate Line Company**

**ATTACHMENT H-18A**

**Trans-Allegheny Interstate Line Company Formula Rate – Appendix A**

**ATTACHMENT H-18B**

**Trans-Allegheny Interstate Line Company Formula Rate Implementation Protocols**

**ATTACHMENT H-19**

**Annual Transmission Rates – Potomac-Appalachian Transmission Highline, L.L.C.**

**ATTACHMENT H-19A**

**Potomac-Appalachian Transmission Highline, L.L.C. Summary**

**ATTACHMENT H-19B**

**Potomac-Appalachian Transmission Highline, L.L.C. Formula Rate  
Implementation Protocols**

**ATTACHMENT H-20**

**Annual Transmission Rates – AEP Transmission Companies (AEPTCo) in the AEP  
Zone**

**ATTACHMENT H-20A**

**AEP Transmission Companies (AEPTCo) in the AEP Zone - Formula Rate Implementation Protocols**  
**ATTACHMENT H-20A APPENDIX A**  
**Transmission Formula Rate Settlement for AEPTCo**  
**ATTACHMENT H-20B - Part I**  
**AEP Transmission Companies (AEPTCo) in the AEP Zone – Blank Formula Rate Template**  
**ATTACHMENT H-20B - Part II**  
**AEP Transmission Companies (AEPTCo) in the AEP Zone – Blank Formula Rate Template**  
**ATTACHMENT H-21**  
**Annual Transmission Rates – American Transmission Systems, Inc. for Network Integration Transmission Service**  
**ATTACHMENT H-21A - ATSI**  
**ATTACHMENT H-21A Appendix A - ATSI**  
**ATTACHMENT H-21A Appendix B - ATSI**  
**ATTACHMENT H-21A Appendix C - ATSI**  
**ATTACHMENT H-21A Appendix C - ATSI [Reserved]**  
**ATTACHMENT H-21A Appendix D – ATSI**  
**ATTACHMENT H-21A Appendix E - ATSI**  
**ATTACHMENT H-21A Appendix F – ATSI [Reserved]**  
**ATTACHMENT H-21A Appendix G - ATSI**  
**ATTACHMENT H-21A Appendix G – ATSI (Credit Adj)**  
**ATTACHMENT H-21B ATSI Protocol**  
**ATTACHMENT H-22**  
**Annual Transmission Rates – DEOK for Network Integration Transmission Service and Point-to-Point Transmission Service**  
**ATTACHMENT H-22A**  
**Duke Energy Ohio and Duke Energy Kentucky (DEOK) Formula Rate Template**  
**ATTACHMENT H-22B**  
**DEOK Formula Rate Implementation Protocols**  
**ATTACHMENT H-22C**  
**Additional provisions re DEOK and Indiana**  
**ATTACHMENT H-23**  
**EP Rock springs annual transmission Rate**  
**ATTACHMENT H-24**  
**EKPC Annual Transmission Rates**  
**ATTACHMENT H-24A APPENDIX A**  
**EKPC Schedule 1A**  
**ATTACHMENT H-24A APPENDIX B**  
**EKPC RTEP**  
**ATTACHMENT H-24A APPENDIX C**  
**EKPC True-up**  
**ATTACHMENT H-24A APPENDIX D**  
**EKPC Depreciation Rates**  
**ATTACHMENT H-24-B**

<b>EKPC Implementation Protocols</b>	
<b>ATTACHMENT H-25</b>	<b>Annual Transmission Rates – Rochelle Municipal Utilities for Network Integration Transmission Service and Point-to-Point Transmission Service in the ComEd Zone</b>
<b>ATTACHMENT H-25A</b>	<b>Formula Rate Protocols for Rochelle Municipal Utilities Using a Historical Formula Rate Template</b>
<b>ATTACHMENT H-25B</b>	<b>Rochelle Municipal Utilities Transmission Cost of Service Formula Rate – Appendix A – Transmission Service Revenue Requirement</b>
<b>ATTACHMENT H-26</b>	<b>Transource West Virginia, LLC Formula Rate Template</b>
<b>ATTACHMENT H-26A</b>	<b>Transource West Virginia, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-27</b>	<b>Annual Transmission Rates – Northeast Transmission Development, LLC</b>
<b>ATTACHMENT H-27A</b>	<b>Northeast Transmission Development, LLC Formula Rate Template</b>
<b>ATTACHMENT H-27B</b>	<b>Northeast Transmission Development, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-28</b>	<b>Annual Transmission Rates – Mid-Atlantic Interstate Transmission, LLC for Network Integration Transmission Service</b>
<b>ATTACHMENT H-28A</b>	<b>Mid-Atlantic Interstate Transmission, LLC Formula Rate Template</b>
<b>ATTACHMENT H-28B</b>	<b>Mid-Atlantic Interstate Transmission, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-29</b>	<b>Annual Transmission Rates – Transource Pennsylvania, LLC</b>
<b>ATTACHMENT H-29A</b>	<b>Transource Pennsylvania, LLC Formula Rate Template</b>
<b>ATTACHMENT H-29B</b>	<b>Transource Pennsylvania, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-30</b>	<b>Annual Transmission Rates – Transource Maryland, LLC</b>
<b>ATTACHMENT H-30A</b>	<b>Transource Maryland, LLC Formula Rate Template</b>
<b>ATTACHMENT H-30B</b>	<b>Transource Maryland, LLC Formula Rate Implementation Protocols</b>
<b>ATTACHMENT H-31</b>	<b>Annual Transmission Revenue Requirement – Ohio Valley Electric Corporation for Network Integration Transmission Service</b>
<b>ATTACHMENT H-A</b>	

**Annual Transmission Rates -- Non-Zone Network Load for Network Integration  
Transmission Service**

**ATTACHMENT I**

**Index of Network Integration Transmission Service Customers**

**ATTACHMENT J**

**PJM Transmission Zones**

**ATTACHMENT K**

**Transmission Congestion Charges and Credits**

**Preface**

**ATTACHMENT K -- APPENDIX**

**Preface**

**1. MARKET OPERATIONS**

- 1.1 Introduction
- 1.2 Cost-Based Offers
- 1.2A Transmission Losses
- 1.3 [Reserved for Future Use]
- 1.4 Market Buyers
- 1.5 Market Sellers
- 1.5A Economic Load Response Participant
- 1.6 Office of the Interconnection
- 1.6A PJM Settlement
- 1.7 General
- 1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process
- 1.9 Prescheduling
- 1.10 Scheduling
- 1.11 Dispatch
- 1.12 Dynamic Transfers

**2. CALCULATION OF LOCATIONAL MARGINAL PRICES**

- 2.1 Introduction
- 2.2 General
- 2.3 Determination of System Conditions Using the State Estimator
- 2.4 Determination of Energy Offers Used in Calculating
- 2.5 Calculation of Real-time Prices
- 2.6 Calculation of Day-ahead Prices
- 2.6A Interface Prices
- 2.7 Performance Evaluation

**3. ACCOUNTING AND BILLING**

- 3.1 Introduction
- 3.2 Market Buyers
- 3.3 Market Sellers
  - 3.3A Economic Load Response Participants
- 3.4 Transmission Customers
- 3.5 Other Control Areas
- 3.6 Metering Reconciliation
- 3.7 Inadvertent Interchange
- 3.8 Market-to-Market Coordination

**4. [Reserved For Future Use]**

- 5. CALCULATION OF CHARGES AND CREDITS FOR TRANSMISSION CONGESTION AND LOSSES**
  - 5.1 Transmission Congestion Charge Calculation
  - 5.2 Transmission Congestion Credit Calculation
  - 5.3 Unscheduled Transmission Service (Loop Flow)
  - 5.4 Transmission Loss Charge Calculation
  - 5.5 Distribution of Total Transmission Loss Charges
- 6. “MUST-RUN” FOR RELIABILITY GENERATION**
  - 6.1 Introduction
  - 6.2 Identification of Facility Outages
  - 6.3 Dispatch for Local Reliability
  - 6.4 Offer Price Caps
  - 6.5 [Reserved]
  - 6.6 Minimum Generator Operating Parameters – Parameter-Limited Schedules
- 6A. [Reserved]**
  - 6A.1 [Reserved]
  - 6A.2 [Reserved]
  - 6A.3 [Reserved]
- 7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS**
  - 7.1 Auctions of Financial Transmission Rights
  - 7.1A Long-Term Financial Transmission Rights Auctions
  - 7.2 Financial Transmission Rights Characteristics
  - 7.3 Auction Procedures
  - 7.4 Allocation of Auction Revenues
  - 7.5 Simultaneous Feasibility
  - 7.6 New Stage 1 Resources
  - 7.7 Alternate Stage 1 Resources
  - 7.8 Elective Upgrade Auction Revenue Rights
  - 7.9 Residual Auction Revenue Rights
  - 7.10 Financial Settlement
  - 7.11 PJM Settlement as Counterparty
- 8. EMERGENCY AND PRE-EMERGENCY LOAD RESPONSE PROGRAM**
  - 8.1 Emergency Load Response and Pre-Emergency Load Response Program Options
  - 8.2 Participant Qualifications
  - 8.3 Metering Requirements
  - 8.4 Registration
  - 8.5 Pre-Emergency Operations
  - 8.6 Emergency Operations
  - 8.7 Verification
  - 8.8 Market Settlements
  - 8.9 Reporting and Compliance
  - 8.10 Non-Hourly Metered Customer Pilot
  - 8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation

**ATTACHMENT L**

<b>List of Transmission Owners</b>	
<b>ATTACHMENT M</b>	
<b>PJM Market Monitoring Plan</b>	
<b>ATTACHMENT M – APPENDIX</b>	
<b>PJM Market Monitor Plan Attachment M Appendix</b>	
I	Confidentiality of Data and Information
II	Development of Inputs for Prospective Mitigation
III	Black Start Service
IV	Deactivation Rates
V	Opportunity Cost Calculation
VI	FTR Forfeiture Rule
VII	Forced Outage Rule
VIII	Data Collection and Verification
<b>ATTACHMENT M-1 (FirstEnergy)</b>	
<b>Energy Procedure Manual for Determining Supplier Total Hourly Energy Obligation</b>	
<b>ATTACHMENT M-2 (First Energy)</b>	
<b>Energy Procedure Manual for Determining Supplier Peak Load Share Procedures for Load Determination</b>	
<b>ATTACHMENT M-2 (ComEd)</b>	
<b>Determination of Capacity Peak Load Contributions and Network Service Peak Load Contributions</b>	
<b>ATTACHMENT M-2 (PSE&amp;G)</b>	
<b>Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-2 (Atlantic City Electric Company)</b>	
<b>Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-2 (Delmarva Power &amp; Light Company)</b>	
<b>Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-2 (Delmarva Power &amp; Light Company)</b>	
<b>Procedures for Determination of Peak Load Contributions and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-2 (Duke Energy Ohio, Inc.)</b>	
<b>Procedures for Determination of Peak Load Contributions, Network Service Peak Load and Hourly Load Obligations for Retail Customers</b>	
<b>ATTACHMENT M-3</b>	
<b>Additional Procedures for Planning of Supplemental Projects</b>	
<b>ATTACHMENT N</b>	
<b>Form of Generation Interconnection Feasibility Study Agreement</b>	
<b>ATTACHMENT N-1</b>	
<b>Form of System Impact Study Agreement</b>	
<b>ATTACHMENT N-2</b>	
<b>Form of Facilities Study Agreement</b>	
<b>ATTACHMENT N-3</b>	



**Form of Optional Interconnection Study Agreement**  
**ATTACHMENT O**

**Form of Interconnection Service Agreement**

- 1.0 Parties
- 2.0 Authority
- 3.0 Customer Facility Specifications
- 4.0 Effective Date
- 5.0 Security
- 6.0 Project Specific Milestones
- 7.0 Provision of Interconnection Service
- 8.0 Assumption of Tariff Obligations
- 9.0 Facilities Study
- 10.0 Construction of Transmission Owner Interconnection Facilities
- 11.0 Interconnection Specifications
- 12.0 Power Factor Requirement
- 12.0A RTU
- 13.0 Charges
- 14.0 Third Party Benefits
- 15.0 Waiver
- 16.0 Amendment
- 17.0 Construction With Other Parts Of The Tariff
- 18.0 Notices
- 19.0 Incorporation Of Other Documents
- 20.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service
- 21.0 Addendum of Interconnection Customer's Agreement  
to Conform with IRS Safe Harbor Provisions for Non-Taxable Status
- 22.0 Addendum of Interconnection Requirements for a Wind Generation Facility
- 23.0 Infrastructure Security of Electric System Equipment and Operations and Control  
Hardware and Software is Essential to Ensure Day-to-Day Reliability and  
Operational Security

**Specifications for Interconnection Service Agreement**

- 1.0 Description of [generating unit(s)] [Merchant Transmission Facilities] (the  
Customer Facility) to be Interconnected with the Transmission System in the PJM  
Region
- 2.0 Rights
- 3.0 Construction Responsibility and Ownership of Interconnection Facilities
- 4.0 Subject to Modification Pursuant to the Negotiated Contract Option
- 4.1 Attachment Facilities Charge
- 4.2 Network Upgrades Charge
- 4.3 Local Upgrades Charge
- 4.4 Other Charges
- 4.5 Cost breakdown
- 4.6 Security Amount Breakdown

**ATTACHMENT O APPENDIX 1: Definitions**

**ATTACHMENT O APPENDIX 2: Standard Terms and Conditions for Interconnections**

**1 Commencement, Term of and Conditions Precedent to**

- Interconnection Service**
  - 1.1 Commencement Date
  - 1.2 Conditions Precedent
  - 1.3 Term
  - 1.4 Initial Operation
  - 1.4A Limited Operation
  - 1.5 Survival
- 2 Interconnection Service**
  - 2.1 Scope of Service
  - 2.2 Non-Standard Terms
  - 2.3 No Transmission Services
  - 2.4 Use of Distribution Facilities
  - 2.5 Election by Behind The Meter Generation
- 3 Modification Of Facilities**
  - 3.1 General
  - 3.2 Interconnection Request
  - 3.3 Standards
  - 3.4 Modification Costs
- 4 Operations**
  - 4.1 General
  - 4.2 [Reserved]
  - 4.3 Interconnection Customer Obligations
  - 4.4 Transmission Interconnection Customer Obligations
  - 4.5 Permits and Rights-of-Way
  - 4.6 No Ancillary Services
  - 4.7 Reactive Power
  - 4.8 Under- and Over-Frequency and Under- and Over- Voltage Conditions
  - 4.9 System Protection and Power Quality
  - 4.10 Access Rights
  - 4.11 Switching and Tagging Rules
  - 4.12 Communications and Data Protocol
  - 4.13 Nuclear Generating Facilities
- 5 Maintenance**
  - 5.1 General
  - 5.2 [Reserved]
  - 5.3 Outage Authority and Coordination
  - 5.4 Inspections and Testing
  - 5.5 Right to Observe Testing
  - 5.6 Secondary Systems
  - 5.7 Access Rights
  - 5.8 Observation of Deficiencies
- 6 Emergency Operations**
  - 6.1 Obligations
  - 6.2 Notice
  - 6.3 Immediate Action
  - 6.4 Record-Keeping Obligations

- 7 Safety**
  - 7.1 General
  - 7.2 Environmental Releases
- 8 Metering**
  - 8.1 General
  - 8.2 Standards
  - 8.3 Testing of Metering Equipment
  - 8.4 Metering Data
  - 8.5 Communications
- 9 Force Majeure**
  - 9.1 Notice
  - 9.2 Duration of Force Majeure
  - 9.3 Obligation to Make Payments
  - 9.4 Definition of Force Majeure
- 10 Charges**
  - 10.1 Specified Charges
  - 10.2 FERC Filings
- 11 Security, Billing And Payments**
  - 11.1 Recurring Charges Pursuant to Section 10
  - 11.2 Costs for Transmission Owner Interconnection Facilities
  - 11.3 No Waiver
  - 11.4 Interest
- 12 Assignment**
  - 12.1 Assignment with Prior Consent
  - 12.2 Assignment Without Prior Consent
  - 12.3 Successors and Assigns
- 13 Insurance**
  - 13.1 Required Coverages for Generation Resources Of More Than 20 Megawatts and Merchant Transmission Facilities
  - 13.1A Required Coverages for Generation Resources Of 20 Megawatts Or Less
  - 13.2 Additional Insureds
  - 13.3 Other Required Terms
  - 13.3A No Limitation of Liability
  - 13.4 Self-Insurance
  - 13.5 Notices; Certificates of Insurance
  - 13.6 Subcontractor Insurance
  - 13.7 Reporting Incidents
- 14 Indemnity**
  - 14.1 Indemnity
  - 14.2 Indemnity Procedures
  - 14.3 Indemnified Person
  - 14.4 Amount Owing
  - 14.5 Limitation on Damages
  - 14.6 Limitation of Liability in Event of Breach
  - 14.7 Limited Liability in Emergency Conditions

- 15 Breach, Cure And Default**
  - 15.1 Breach
  - 15.2 Continued Operation
  - 15.3 Notice of Breach
  - 15.4 Cure and Default
  - 15.5 Right to Compel Performance
  - 15.6 Remedies Cumulative
- 16 Termination**
  - 16.1 Termination
  - 16.2 Disposition of Facilities Upon Termination
  - 16.3 FERC Approval
  - 16.4 Survival of Rights
- 17 Confidentiality**
  - 17.1 Term
  - 17.2 Scope
  - 17.3 Release of Confidential Information
  - 17.4 Rights
  - 17.5 No Warranties
  - 17.6 Standard of Care
  - 17.7 Order of Disclosure
  - 17.8 Termination of Interconnection Service Agreement
  - 17.9 Remedies
  - 17.10 Disclosure to FERC or its Staff
  - 17.11 No Interconnection Party Shall Disclose Confidential Information
  - 17.12 Information that is Public Domain
  - 17.13 Return or Destruction of Confidential Information
- 18 Subcontractors**
  - 18.1 Use of Subcontractors
  - 18.2 Responsibility of Principal
  - 18.3 Indemnification by Subcontractors
  - 18.4 Subcontractors Not Beneficiaries
- 19 Information Access And Audit Rights**
  - 19.1 Information Access
  - 19.2 Reporting of Non-Force Majeure Events
  - 19.3 Audit Rights
- 20 Disputes**
  - 20.1 Submission
  - 20.2 Rights Under The Federal Power Act
  - 20.3 Equitable Remedies
- 21 Notices**
  - 21.1 General
  - 21.2 Emergency Notices
  - 21.3 Operational Contacts
- 22 Miscellaneous**
  - 22.1 Regulatory Filing
  - 22.2 Waiver

	22.3	Amendments and Rights Under the Federal Power Act
	22.4	Binding Effect
	22.5	Regulatory Requirements
<b>23</b>		<b>Representations And Warranties</b>
	23.1	General
<b>24</b>		<b>Tax Liability</b>
	24.1	Safe Harbor Provisions
	24.2	Tax Indemnity
	24.3	Taxes Other Than Income Taxes
	24.4	Income Tax Gross-Up
	24.5	Tax Status
<b>ATTACHMENT O - SCHEDULE A</b>		
		<b>Customer Facility Location/Site Plan</b>
<b>ATTACHMENT O - SCHEDULE B</b>		
		<b>Single-Line Diagram</b>
<b>ATTACHMENT O - SCHEDULE C</b>		
		<b>List of Metering Equipment</b>
<b>ATTACHMENT O - SCHEDULE D</b>		
		<b>Applicable Technical Requirements and Standards</b>
<b>ATTACHMENT O - SCHEDULE E</b>		
		<b>Schedule of Charges</b>
<b>ATTACHMENT O - SCHEDULE F</b>		
		<b>Schedule of Non-Standard Terms &amp; Conditions</b>
<b>ATTACHMENT O - SCHEDULE G</b>		
		<b>Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status</b>
<b>ATTACHMENT O - SCHEDULE H</b>		
		<b>Interconnection Requirements for a Wind Generation Facility</b>
<b>ATTACHMENT O-1</b>		
		<b>Form of Interim Interconnection Service Agreement</b>
<b>ATTACHMENT P</b>		
		<b>Form of Interconnection Construction Service Agreement</b>
	1.0	Parties
	2.0	Authority
	3.0	Customer Facility
	4.0	Effective Date and Term
	4.1	Effective Date
	4.2	Term
	4.3	Survival
	5.0	Construction Responsibility
	6.0	[Reserved.]
	7.0	Scope of Work
	8.0	Schedule of Work
	9.0	[Reserved.]
	10.0	Notices
	11.0	Waiver

- 12.0 Amendment
- 13.0 Incorporation Of Other Documents
- 14.0 Addendum of Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status
- 15.0 Addendum of Non-Standard Terms and Conditions for Interconnection Service
- 16.0 Addendum of Interconnection Requirements for a Wind Generation Facility
- 17.0 Infrastructure Security of Electric System Equipment and Operations and Control Hardware and Software is Essential to Ensure Day-to-Day Reliability and Operational Security

## **ATTACHMENT P - APPENDIX 1 – DEFINITIONS**

## **ATTACHMENT P - APPENDIX 2 – STANDARD CONSTRUCTION TERMS AND CONDITIONS**

### **Preamble**

#### **1 Facilitation by Transmission Provider**

#### **2 Construction Obligations**

- 2.1 Interconnection Customer Obligations
- 2.2 Transmission Owner Interconnection Facilities and Merchant Network Upgrades
- 2.2A Scope of Applicable Technical Requirements and Standards
- 2.3 Construction By Interconnection Customer
- 2.4 Tax Liability
- 2.5 Safety
- 2.6 Construction-Related Access Rights
- 2.7 Coordination Among Constructing Parties

#### **3 Schedule of Work**

- 3.1 Construction by Interconnection Customer
- 3.2 Construction by Interconnected Transmission Owner
  - 3.2.1 Standard Option
  - 3.2.2 Negotiated Contract Option
  - 3.2.3 Option to Build
- 3.3 Revisions to Schedule of Work
- 3.4 Suspension
  - 3.4.1 Costs
  - 3.4.2 Duration of Suspension
- 3.5 Right to Complete Transmission Owner Interconnection Facilities
- 3.6 Suspension of Work Upon Default
- 3.7 Construction Reports
- 3.8 Inspection and Testing of Completed Facilities
- 3.9 Energization of Completed Facilities
- 3.10 Interconnected Transmission Owner's Acceptance of Facilities Constructed by Interconnection Customer

#### **4 Transmission Outages**

- 4.1 Outages; Coordination

#### **5 Land Rights; Transfer of Title**

- 5.1 Grant of Easements and Other Land Rights

5.2	Construction of Facilities on Interconnection Customer Property
5.3	Third Parties
5.4	Documentation
5.5	Transfer of Title to Certain Facilities Constructed By Interconnection Customer
5.6	Liens
<b>6</b>	<b>Warranties</b>
6.1	Interconnection Customer Warranty
6.2	Manufacturer Warranties
<b>7</b>	<b>[Reserved.]</b>
<b>8</b>	<b>[Reserved.]</b>
<b>9</b>	<b>Security, Billing And Payments</b>
9.1	Adjustments to Security
9.2	Invoice
9.3	Final Invoice
9.4	Disputes
9.5	Interest
9.6	No Waiver
<b>10</b>	<b>Assignment</b>
10.1	Assignment with Prior Consent
10.2	Assignment Without Prior Consent
10.3	Successors and Assigns
<b>11</b>	<b>Insurance</b>
11.1	Required Coverages For Generation Resources Of More Than 20 Megawatts and Merchant Transmission Facilities
11.1A	Required Coverages For Generation Resources of 20 Megawatts Or Less
11.2	Additional Insureds
11.3	Other Required Terms
11.3A	No Limitation of Liability
11.4	Self-Insurance
11.5	Notices; Certificates of Insurance
11.6	Subcontractor Insurance
11.7	Reporting Incidents
<b>12</b>	<b>Indemnity</b>
12.1	Indemnity
12.2	Indemnity Procedures
12.3	Indemnified Person
12.4	Amount Owing
12.5	Limitation on Damages
12.6	Limitation of Liability in Event of Breach
12.7	Limited Liability in Emergency Conditions
<b>13</b>	<b>Breach, Cure And Default</b>
13.1	Breach
13.2	Notice of Breach
13.3	Cure and Default

	13.3.1	Cure of Breach
	13.4	Right to Compel Performance
	13.5	Remedies Cumulative
<b>14</b>		<b>Termination</b>
	14.1	Termination
	14.2	[Reserved.]
	14.3	Cancellation By Interconnection Customer
	14.4	Survival of Rights
<b>15</b>		<b>Force Majeure</b>
	15.1	Notice
	15.2	Duration of Force Majeure
	15.3	Obligation to Make Payments
	15.4	Definition of Force Majeure
<b>16</b>		<b>Subcontractors</b>
	16.1	Use of Subcontractors
	16.2	Responsibility of Principal
	16.3	Indemnification by Subcontractors
	16.4	Subcontractors Not Beneficiaries
<b>17</b>		<b>Confidentiality</b>
	17.1	Term
	17.2	Scope
	17.3	Release of Confidential Information
	17.4	Rights
	17.5	No Warranties
	17.6	Standard of Care
	17.7	Order of Disclosure
	17.8	Termination of Construction Service Agreement
	17.9	Remedies
	17.10	Disclosure to FERC or its Staff
	17.11	No Construction Party Shall Disclose Confidential Information of Another Construction Party 17.12 Information that is Public Domain
	17.13	Return or Destruction of Confidential Information
<b>18</b>		<b>Information Access And Audit Rights</b>
	18.1	Information Access
	18.2	Reporting of Non-Force Majeure Events
	18.3	Audit Rights
<b>19</b>		<b>Disputes</b>
	19.1	Submission
	19.2	Rights Under The Federal Power Act
	19.3	Equitable Remedies
<b>20</b>		<b>Notices</b>
	20.1	General
	20.2	Operational Contacts
<b>21</b>		<b>Miscellaneous</b>
	21.1	Regulatory Filing
	21.2	Waiver



21.3	Amendments and Rights under the Federal Power Act
21.4	Binding Effect
21.5	Regulatory Requirements
<b>22</b>	<b>Representations and Warranties</b>
22.1	General
<b>ATTACHMENT P - SCHEDULE A</b>	
	<b>Site Plan</b>
<b>ATTACHMENT P - SCHEDULE B</b>	
	<b>Single-Line Diagram of Interconnection Facilities</b>
<b>ATTACHMENT P - SCHEDULE C</b>	
	<b>Transmission Owner Interconnection Facilities to be Built by Interconnected Transmission Owner</b>
<b>ATTACHMENT P - SCHEDULE D</b>	
	<b>Transmission Owner Interconnection Facilities to be Built by Interconnection Customer Pursuant to Option to Build</b>
<b>ATTACHMENT P - SCHEDULE E</b>	
	<b>Merchant Network Upgrades to be Built by Interconnected Transmission Owner</b>
<b>ATTACHMENT P - SCHEDULE F</b>	
	<b>Merchant Network Upgrades to be Built by Interconnection Customer Pursuant to Option to Build</b>
<b>ATTACHMENT P - SCHEDULE G</b>	
	<b>Customer Interconnection Facilities</b>
<b>ATTACHMENT P - SCHEDULE H</b>	
	<b>Negotiated Contract Option Terms</b>
<b>ATTACHMENT P - SCHEDULE I</b>	
	<b>Scope of Work</b>
<b>ATTACHMENT P - SCHEDULE J</b>	
	<b>Schedule of Work</b>
<b>ATTACHMENT P - SCHEDULE K</b>	
	<b>Applicable Technical Requirements and Standards</b>
<b>ATTACHMENT P - SCHEDULE L</b>	
	<b>Interconnection Customer's Agreement to Confirm with IRS Safe Harbor Provisions For Non-Taxable Status</b>
<b>ATTACHMENT P - SCHEDULE M</b>	
	<b>Schedule of Non-Standard Terms and Conditions</b>
<b>ATTACHMENT P - SCHEDULE N</b>	
	<b>Interconnection Requirements for a Wind Generation Facility</b>
<b>ATTACHMENT Q</b>	
	<b>PJM Credit Policy</b>
<b>ATTACHMENT R</b>	
	<b>Lost Revenues Of PJM Transmission Owners And Distribution of Revenues Remitted By MISO, SECA Rates to Collect PJM Transmission Owner Lost Revenues Under Attachment X, And Revenues From PJM Existing Transactions</b>
<b>ATTACHMENT S</b>	
	<b>Form of Transmission Interconnection Feasibility Study Agreement</b>
<b>ATTACHMENT T</b>	

Identification of Merchant Transmission Facilities	
ATTACHMENT U	
Independent Transmission Companies	
ATTACHMENT V	
Form of ITC Agreement	
ATTACHMENT W	
COMMONWEALTH EDISON COMPANY	
ATTACHMENT X	
Seams Elimination Cost Assignment Charges	
NOTICE OF ADOPTION OF NERC TRANSMISSION LOADING RELIEF	
PROCEDURES	
NOTICE OF ADOPTION OF LOCAL TRANSMISSION LOADING RELIEF	
PROCEDURES	
SCHEDULE OF PARTIES ADOPTING LOCAL TRANSMISSION LOADING	
RELIEF PROCEDURES	
ATTACHMENT Y	
Forms of Screens Process Interconnection Request (For Generation Facilities of 2	
MW or less)	
ATTACHMENT Z	
Certification Codes and Standards	
ATTACHMENT AA	
Certification of Small Generator Equipment Packages	
ATTACHMENT BB	
Form of Certified Inverter-Based Generating Facility No Larger Than 10 kW	
Interconnection Service Agreement	
ATTACHMENT CC	
Form of Certificate of Completion	
(Small Generating Inverter Facility No Larger Than 10 kW)	
ATTACHMENT DD	
Reliability Pricing Model	
ATTACHMENT EE	
Form of Upgrade Request	
ATTACHMENT FF	
[Reserved]	
ATTACHMENT GG	
Form of Upgrade Construction Service Agreement	
Article 1 – Definitions And Other Documents	
1.0 Defined Terms	
1.1 Incorporation of Other Documents	
Article 2 – Responsibility for Direct Assignment Facilities or Customer-Funded	
Upgrades	
2.0 New Service Customer Financial Responsibilities	
2.1 Obligation to Provide Security	
2.2 Failure to Provide Security	
2.3 Costs	
2.4 Transmission Owner Responsibilities	

- Article 3 – Rights To Transmission Service
  - 3.0 No Transmission Service
- Article 4 – Early Termination
  - 4.0 Termination by New Service Customer
- Article 5 – Rights
  - 5.0 Rights
    - 5.1 Amount of Rights Granted
    - 5.2 Availability of Rights Granted
    - 5.3 Credits
- Article 6 – Miscellaneous
  - 6.0 Notices
  - 6.1 Waiver
  - 6.2 Amendment
  - 6.3 No Partnership
  - 6.4 Counterparts

**ATTACHMENT GG - APPENDIX I –**

**SCOPE AND SCHEDULE OF WORK FOR DIRECT ASSIGNMENT  
FACILITIES OR CUSTOMER-FUNDED UPGRADES TO BE BUILT BY  
TRANSMISSION OWNER**

**ATTACHMENT GG - APPENDIX II - DEFINITIONS**

- 1 Definitions
  - 1.1 Affiliate
  - 1.2 Applicable Laws and Regulations
  - 1.3 Applicable Regional Reliability Council
  - 1.4 Applicable Standards
  - 1.5 Breach
  - 1.6 Breaching Party
  - 1.7 Cancellation Costs
  - 1.8 Commission
  - 1.9 Confidential Information
  - 1.10 Constructing Entity
  - 1.11 Control Area
  - 1.12 Costs
  - 1.13 Default
  - 1.14 Delivering Party
  - 1.15 Emergency Condition
  - 1.16 Environmental Laws
  - 1.17 Facilities Study
  - 1.18 Federal Power Act
  - 1.19 FERC
  - 1.20 Firm Point-To-Point
  - 1.21 Force Majeure
  - 1.22 Good Utility Practice
  - 1.23 Governmental Authority
  - 1.24 Hazardous Substances
  - 1.25 Incidental Expenses

- 1.26 Local Upgrades
- 1.27 Long-Term Firm Point-To-Point Transmission Service
- 1.28 MAAC
- 1.29 MAAC Control Zone
- 1.30 NERC
- 1.31 Network Upgrades
- 1.32 Office of the Interconnection
- 1.33 Operating Agreement of the PJM Interconnection, L.L.C. or Operating Agreement
- 1.34 Part I
- 1.35 Part II
- 1.36 Part III
- 1.37 Part IV
- 1.38 Part VI
- 1.39 PJM Interchange Energy Market
- 1.40 PJM Manuals
- 1.41 PJM Region
- 1.42 PJM West Region
- 1.43 Point(s) of Delivery
- 1.44 Point(s) of Receipt
- 1.45 Project Financing
- 1.46 Project Finance Entity
- 1.47 Reasonable Efforts
- 1.48 Receiving Party
- 1.49 Regional Transmission Expansion Plan
- 1.50 Schedule and Scope of Work
- 1.51 Security
- 1.52 Service Agreement
- 1.53 State
- 1.54 Transmission System
- 1.55 VACAR

## **ATTACHMENT GG - APPENDIX III – GENERAL TERMS AND CONDITIONS**

- 1.0 Effective Date and Term
  - 1.1 Effective Date
  - 1.2 Term
  - 1.3 Survival
- 2.0 Facilitation by Transmission Provider
- 3.0 Construction Obligations
  - 3.1 Direct Assignment Facilities or Customer-Funded Upgrades
  - 3.2 Scope of Applicable Technical Requirements and Standards
- 4.0 Tax Liability
  - 4.1 New Service Customer Payments Taxable
  - 4.2 Income Tax Gross-Up
  - 4.3 Private Letter Ruling
  - 4.4 Refund
  - 4.5 Contests

- 4.6 Taxes Other Than Income Taxes
  - 4.7 Tax Status
- 5.0 Safety
  - 5.1 General
  - 5.2 Environmental Releases
- 6.0 Schedule Of Work
  - 6.1 Standard Option
  - 6.2 Option to Build
  - 6.3 Revisions to Schedule and Scope of Work
  - 6.4 Suspension
- 7.0 Suspension of Work Upon Default
  - 7.1 Notification and Correction of Defects
- 8.0 Transmission Outages
  - 8.1 Outages; Coordination
- 9.0 Security, Billing and Payments
  - 9.1 Adjustments to Security
  - 9.2 Invoice
  - 9.3 Final Invoice
  - 9.4 Disputes
  - 9.5 Interest
  - 9.6 No Waiver
- 10.0 Assignment
  - 10.1 Assignment with Prior Consent
  - 10.2 Assignment Without Prior Consent
  - 10.3 Successors and Assigns
- 11.0 Insurance
  - 11.1 Required Coverages
  - 11.2 Additional Insureds
  - 11.3 Other Required Terms
  - 11.4 No Limitation of Liability
  - 11.5 Self-Insurance
  - 11.6 Notices: Certificates of Insurance
  - 11.7 Subcontractor Insurance
  - 11.8 Reporting Incidents
- 12.0 Indemnity
  - 12.1 Indemnity
  - 12.2 Indemnity Procedures
  - 12.3 Indemnified Person
  - 12.4 Amount Owing
  - 12.5 Limitation on Damages
  - 12.6 Limitation of Liability in Event of Breach
  - 12.7 Limited Liability in Emergency Conditions
- 13.0 Breach, Cure And Default
  - 13.1 Breach
  - 13.2 Notice of Breach
  - 13.3 Cure and Default

- 13.4 Right to Compel Performance
- 13.5 Remedies Cumulative
- 14.0 Termination
  - 14.1 Termination
  - 14.2 Cancellation By New Service Customer
  - 14.3 Survival of Rights
  - 14.4 Filing at FERC
- 15.0 Force Majeure
  - 15.1 Notice
  - 15.2 Duration of Force Majeure
  - 15.3 Obligation to Make Payments
- 16.0 Confidentiality
  - 16.1 Term
  - 16.2 Scope
  - 16.3 Release of Confidential Information
  - 16.4 Rights
  - 16.5 No Warranties
  - 16.6 Standard of Care
  - 16.7 Order of Disclosure
  - 16.8 Termination of Upgrade Construction Service Agreement
  - 16.9 Remedies
  - 16.10 Disclosure to FERC or its Staff
  - 16.11 No Party Shall Disclose Confidential Information of Party 16.12  
Information that is Public Domain
  - 16.13 Return or Destruction of Confidential Information
- 17.0 Information Access And Audit Rights
  - 17.1 Information Access
  - 17.2 Reporting of Non-Force Majeure Events
  - 17.3 Audit Rights
  - 17.4 Waiver
  - 17.5 Amendments and Rights under the Federal Power Act
  - 17.6 Regulatory Requirements
- 18.0 Representation and Warranties
  - 18.1 General
- 19.0 Inspection and Testing of Completed Facilities
  - 19.1 Coordination
  - 19.2 Inspection and Testing
  - 19.3 Review of Inspection and Testing by Transmission Owner
  - 19.4 Notification and Correction of Defects
  - 19.5 Notification of Results
- 20.0 Energization of Completed Facilities
- 21.0 Transmission Owner's Acceptance of Facilities Constructed  
by New Service Customer
- 22.0 Transfer of Title to Certain Facilities Constructed By New Service Customer
- 23.0 Liens

**ATTACHMENT HH – RATES, TERMS, AND CONDITIONS OF SERVICE FOR PJMSETTLEMENT, INC.**

**ATTACHMENT II – MTEP PROJECT COST RECOVERY FOR ATSI ZONE**

**ATTACHMENT JJ – MTEP PROJECT COST RECOVERY FOR DEOK ZONE**

**ATTACHMENT KK - FORM OF DESIGNATED ENTITY AGREEMENT**

**ATTACHMENT LL - FORM OF INTERCONNECTION COORDINATION AGREEMENT**

**ATTACHMENT MM – FORM OF PSEUDO-TIE AGREEMENT – WITH NATIVE BA AS PARTY**

**ATTACHMENT MM-1 – FORM OF SYSTEM MODIFICATION COST REIMBURSEMENT AGREEMENT – PSEUDO-TIE INTO PJM**

**ATTACHMENT NN – FORM OF PSEUDO-TIE AGREEMENT WITHOUT NATIVE BA AS PARTY**

**ATTACHMENT OO – FORM OF DYNAMIC SCHEDULE AGREEMENT INTO THE PJM REGION**

**ATTACHMENT PP – FORM OF FIRM TRANSMISSION FEASIBILITY STUDY AGREEMENT**

## **Definitions – A - B**

### **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.

### **Additional Day-ahead Scheduling Reserves Requirement:**

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

### **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” 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 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 Resource Price Adder:**

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

**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, 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 Demand Resource Price Decrement:**

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

**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 Capacity Resource Price Decrement:**

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

#### **Base Day-ahead Scheduling Reserves Requirement:**

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

#### **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 Demand Resource:**

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

**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.

**Breach:**

“Breach” shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or 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 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.



## **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 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 hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

**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.

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

**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.

**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, or Operating Agreement, Schedule 1, 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.

**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.

**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.

**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.

**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 used by 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 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 the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

**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 Score:**

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

**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, subpart A.

**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 Scheduling Reserves:**

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

**Day-ahead Scheduling Reserves Market:**

“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

**Day-ahead Scheduling Reserves Requirement:**

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

**Day-ahead Scheduling Reserves Resources:**

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

**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 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.

**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.

**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 – L – M – N**

### **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.

**Limited Resource Price Decrement:**

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

**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 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 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 units, 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 Regulation or Tier 2 Synchronized 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 units, the LOC Deviation shall

mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output 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 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.

**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.

**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, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant 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 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 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 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 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, and the last generator breaker opening as measured by PJM's State Estimator.

**MISO:**

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

**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.

**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) 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 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 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 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 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 Service Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on April 30 and October 31 of each year shall collectively comprise a New Services Queue.

**New Services Queue Closing Date:**

“New Services Queue Closing Date” shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the six-month period ending on such date.

**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 create the starting point of a monotonically increasing incremental offer curve for a generating unit.

**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-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.

### **SCHEDULE 9-3**

#### **Market Support Service**

- a) Market Support Service comprises all of the activities of PJM associated with supporting the operation of the PJM Interchange Energy Market and related functions, as described in Operating Agreement, Schedule 1 and Tariff, Attachment K-Appendix, including, but not limited to, market modeling and scheduling functions, locational marginal pricing support, and support of PJM's Internet-based customer transaction tools. PJM provides this service to customers using Point-to-Point or Network Integration Transmission Service under the Tariff, to Generation Providers, as defined below, and to entities that submit offers to sell or bids to buy energy in the PJM Interchange Energy Market.
- b) PJM will charge each user of Market Support Service each month a charge equal to the sum of: (i) the MS Service Rate, Component 1, as stated below, times (1) the total quantity in MWhs of energy delivered to load (including losses and net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region or for export from such region during such month by such user as a customer under Point-to-Point Transmission Service (other than Wheeling-Through Service, as defined below) or Network Integration Transmission Service, plus (2) the total quantity in MWhs of energy input into the Transmission System during such month by such user as a Generation Provider, as defined below, plus (3) the total quantity in MWhs of all accepted Increment Offers and accepted Decrement Bids, and all accepted "Up-to" Congestion Transactions submitted pursuant to Tariff, Attachment K-Appendix, section 1.10.1A(c), submitted by such user during such month; plus (ii) the MS Service Rate Component 2, as stated below, times the number of Bid/Offer Segments, as defined below, submitted by such user during such month. For purposes of this Schedule 9-3, Wheeling-Through Service is Point-to-Point Transmission Service for which both the Point of Receipt and the Point of Delivery are at interconnections of the PJM Region with other Control Areas.
- c) For purposes of this Schedule 9-3, a Generation Provider shall be: (i) a Generation Owner, as such term is defined in the Operating Agreement; provided, however, that if a Generation Owner is not the entity credited on PJM's records for the energy input into the Transmission System from the generation facilities owned or leased (with rights equivalent to ownership) by such Generation Owner, as, for example, in the case of a qualifying facility selling energy to a public utility pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978, then, with respect to such energy, the Generation Provider shall be the entity credited on PJM's records for the energy input into the Transmission System from such generation facilities; (ii) a Network Customer or Point-to-Point Transmission Service customer, with respect to energy arranged by such customer to be delivered for import into the PJM Region; or (iii) a Market Seller with respect to energy arranged by such Market Seller to be delivered for import to the boundaries of the PJM Region and for which there is no separately identifiable Transmission Customer. As the term is used in this Schedule 9-3, energy "credited on PJM's records" does not necessarily mean that a monetary credit resulted on any billing statement provided by PJM.
- d) For purposes of this Schedule 9-3, a Bid/Offer Segment shall be each price/quantity pair submitted into the Day-ahead Energy Market, including those submitted in the generation rebidding period pursuant to Tariff, Attachment K-Appendix, section 1.10.9(a). Segments shall



be hourly for each bid to purchase energy, each Increment Offer, each Decrement Bid, each “Up-to” Congestion Transaction, and each Day-ahead Pseudo-Tie Transaction. Segments shall be daily for each offer to sell other than an Increment Offer. Each “Up-to” Congestion Transaction also shall be considered a Bid/Offer Segment.

e) The MS Service Rate, Component 1 shall be as follows:

Commencing January 1, 2017:	\$0.0463 per MWh
Commencing January 1, 2019:	\$0.0475 per MWh
Commencing January 1, 2020:	\$0.0487 per MWh
Commencing January 1, 2021:	\$0.0499 per MWh
Commencing January 1, 2022:	\$0.0511 per MWh
Commencing January 1, 2023:	\$0.0524 per MWh
Commencing January 1, 2024:	\$0.0527 per MWh

Users charged the MS Service Rate, Component 1, shall receive a credit in the amount the user is charged the PJMSettlement Market Service Rate set forth in Schedule 9-PJMSettlement during the same billing period.

f) The MS Service Rate, Component 2 shall be as follows:

Commencing January 1, 2017:	\$0.0693 per Bid/Offer Segment
Commencing January 1, 2019:	\$0.0710 per Bid/Offer Segment
Commencing January 1, 2020:	\$0.0728 per Bid/Offer Segment
Commencing January 1, 2021:	\$0.0746 per Bid/Offer Segment
Commencing January 1, 2022:	\$0.0765 per Bid/Offer Segment
Commencing January 1, 2023:	\$0.0784 per Bid/Offer Segment
Commencing January 1, 2024:	\$0.0789 per Bid/Offer Segment

## **1.10 Scheduling.**

### **1.10.1 General.**

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

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

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

#### **1.10.1A Day-ahead Energy Market Scheduling.**

The following actions shall occur not later than 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the

Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

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

(c-2) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock

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

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.
- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's

Offer Data specification, Operating Agreement Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;
- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of

the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

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

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

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

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

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

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

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

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

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

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

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

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

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each



clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

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

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

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead

Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

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

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

### **1.10.1B Demand Bid Scheduling and Screening**

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

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

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

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.

2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

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

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

### **1.10.2 Pool-scheduled Resources.**

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

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

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

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

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

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

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

### **1.10.3 Self-scheduled Resources.**

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

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

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

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

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

#### **1.10.4 Capacity Resources.**

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

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

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

#### **1.10.5 External Resources.**

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

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

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

#### **1.10.6 External Market Buyers.**

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

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

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

#### **1.10.6A Transmission Loading Relief Customers.**

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 10:30 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy

schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

#### **1.10.7 Bilateral Transactions.**

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

#### **1.10.8 Office of the Interconnection Responsibilities.**

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated

flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

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

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



(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

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

#### **1.10.9 Hourly Scheduling.**

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable

Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

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

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

#### **1.10.9A Updating Offers in Real-time**

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

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

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

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

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

### **1.10.9B Offer Parameter Flexibility**

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

period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

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

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

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

### 3.8 Market-to-Market Coordination

The Office of the Interconnection shall charge or credit a Market Participant for the transmission congestion from the Market Participant's Pseudo-Tie generator within MISO to the PJM-MISO interface resulting from market-to-market coordination pursuant to this Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8. The Office of the Interconnection shall calculate such charges and credits for the Real-time Energy Market for each Pseudo-Tie generator using the following formulas.

$$RT\ Charge / Credit_{PT} = RT\ CLMP_{PT} * DevMW_{PT}$$

Where:

$$RTCLMP_{PT} = \sum RT\ ShadowPrice_{FG} * (RT\ ShiftFactor_{FG,PT} - RT\ ShiftFactor_{FG,Interface})$$

$$RTCLMP_{PT} =$$

Real-time congestion LMP for the path from the Pseudo-Tie generator to the MISO-PJM common interface.

$$RT\ ShadowPrice_{FG} =$$

Real-time shadow price for each M2M Flowgate calculated in accordance with the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

$$RT\ ShiftFactor_{FG,PT} =$$

Real-time shift factor for the Pseudo-Tie generator and each M2M Flowgate.

Where:

$$DevMW_{PT} = (RT\ MW_{PT} - DA\ MW_{PT})$$

$$DevMW_{PT} =$$

The megawatt deviation between the cleared megawatts in the Day-ahead Energy Market and Real-time Energy Market megawatt output for a Pseudo-Tie generator.

$$RT\ MW_{PT} =$$

Real-time Energy Market megawatt output for the Pseudo-Tie generator.

$$DA\ MW_{PT} =$$

Cleared and committed megawatts for a Pseudo-Tie generator in the Day-ahead Energy Market.

The dollars refunded to or collected from the Pseudo-Tie generator will be, respectively, distributed from or added to the Balancing Congestion Charges fund.

Section(s) of the  
PJM Operating Agreement  
(Clean Format)

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**OPERATING AGREEMENT  
TABLE OF CONTENTS**

1. DEFINITIONS
  - OA Definitions - A - B
  - OA Definitions - C - D
  - OA Definitions - E - F
  - OA Definitions - G - H
  - OA Definitions - I - L
  - OA Definitions - M - N
  - OA Definitions - O - P
  - OA Definitions - Q - R
  - OA Definitions - S - T
  - OA Definitions - U - Z
2. FORMATION, NAME; PLACE OF BUSINESS
  - 2.1 Formation of LLC; Certificate of Formation
  - 2.2 Name of LLC
  - 2.3 Place of Business
  - 2.4 Registered Office and Registered Agent
3. PURPOSES AND POWERS OF LLC
  - 3.1 Purposes
  - 3.2 Powers
4. EFFECTIVE DATE AND TERMINATION
  - 4.1 Effective Date and Termination
  - 4.2 Governing Law
5. WORKING CAPITAL AND CAPITAL CONTRIBUTIONS
  - 5.1 Funding of Working Capital and Capital Contributions
  - 5.2 Contributions to Association
6. TAX STATUS AND DISTRIBUTIONS
  - 6.1 Tax Status
  - 6.2 Return of Capital Contributions
  - 6.3 Liquidating Distribution
7. PJM BOARD
  - 7.1 Composition
  - 7.2 Qualifications
  - 7.3 Term of Office
  - 7.4 Quorum
  - 7.5 Operating and Capital Budgets
  - 7.6 By-laws
  - 7.7 Duties and Responsibilities of the PJM Board
8. MEMBERS COMMITTEE
  - 8.1 Sectors
  - 8.2 Representatives
  - 8.3 Meetings



- 8.4 Manner of Acting
- 8.5 Chair and Vice Chair of the Members Committee
- 8.6 Senior, Standing, and Other Committees
- 8.7 User Groups
- 8.8 Powers of the Members Committee
- 9. OFFICERS
  - 9.1 Election and Term
  - 9.2 President
  - 9.3 Secretary
  - 9.4 Treasurer
  - 9.5 Renewal of Officers; Vacancies
  - 9.6 Compensation
- 10. OFFICE OF THE INTERCONNECTION
  - 10.1 Establishment
  - 10.2 Processes and Organization
    - 10.2.1 Financial Interests
  - 10.3 Confidential Information
  - 10.4 Duties and Responsibilities
- 11. MEMBERS
  - 11.1 Management Rights
  - 11.2 Other Activities
  - 11.3 Member Responsibilities
  - 11.4 Regional Transmission Expansion Planning Protocol
  - 11.5 Member Right to Petition
  - 11.6 Membership Requirements
  - 11.7 Associate Membership Requirements
- 12. TRANSFERS OF MEMBERSHIP INTEREST
- 13. INTERCHANGE
  - 13.1 Interchange Arrangements with Non-Members
  - 13.2 Energy Market
- 14. METERING
  - 14.1 Installation, Maintenance and Reading of Meters
  - 14.2 Metering Procedures
  - 14.3 Integrated Megawatt-Hours
  - 14.4 Meter Locations
  - 14.5 Metering of Behind The Meter Generation
- 14A. TRANSMISSION LOSSES
  - 14A.1 Description of Transmission Losses
  - 14A.2 Inclusion of State Estimator Transmission Losses
  - 14A.3 Other Losses
- 15. ENFORCEMENT OF OBLIGATIONS
  - 15.1 Failure to Meet Obligations
  - 15.2 Enforcement of Obligations
  - 15.3 Obligations to a Member in Default
  - 15.4 Obligations of a Member in Default
  - 15.5 No Implied Waiver

- 15.6 Limitation on Claims
- 16. LIABILITY AND INDEMNITY
  - 16.1 Members
  - 16.2 LLC Indemnified Parties
  - 16.3 Workers Compensation Claims
  - 16.4 Limitation of Liability
  - 16.5 Resolution of Disputes
  - 16.6 Gross Negligence or Willful Misconduct
  - 16.7 Insurance
- 17. MEMBER REPRESENTATIONS, WARRANTIES AND COVENANTS
  - 17.1 Representations and Warranties
  - 17.2 Municipal Electric Systems
  - 17.3 Survival
- 18. MISCELLANEOUS PROVISIONS
  - 18.1 [Reserved.]
  - 18.2 Fiscal and Taxable Year
  - 18.3 Reports
  - 18.4 Bank Accounts; Checks, Notes and Drafts
  - 18.5 Books and Records
  - 18.6 Amendment
  - 18.7 Interpretation
  - 18.8 Severability
  - 18.9 Catastrophic Force Majeure
  - 18.10 Further Assurances
  - 18.11 Seal
  - 18.12 Counterparts
  - 18.13 Costs of Meetings
  - 18.14 Notice
  - 18.15 Headings
  - 18.16 No Third-Party Beneficiaries
  - 18.17 Confidentiality
  - 18.18 Termination and Withdrawal
    - 18.18.1 Termination
    - 18.18.2 Withdrawal
    - 18.18.3 Winding Up

#### RESOLUTION REGARDING ELECTION OF DIRECTORS

#### SCHEDULE 1 – PJM INTERCHANGE ENERGY MARKET

- 1. MARKET OPERATIONS
  - 1.1 Introduction
  - 1.2 Cost-Based Offers
  - 1.2A Transmission Losses
  - 1.3 [Reserved for Future Use]
  - 1.4 Market Buyers
  - 1.5 Market Sellers
  - 1.5A Economic Load Response Participant
  - 1.6 Office of the Interconnection

- 1.6A PJMSettlement
- 1.7 General
- 1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process
- 1.9 Prescheduling
- 1.10 Scheduling
- 1.11 Dispatch
- 1.12 Dynamic Transfers
- 2. CALCULATION OF LOCATIONAL MARGINAL PRICES
  - 2.1 Introduction
  - 2.2 General
  - 2.3 Determination of System Conditions Using the State Estimator
  - 2.4 Determination of Energy Offers Used in Calculating Real-time Prices
  - 2.5 Calculation of Real-time Prices
  - 2.6 Calculation of Day-ahead Prices
  - 2.6A Interface Prices
  - 2.7 Performance Evaluation
- 3. ACCOUNTING AND BILLING
  - 3.1 Introduction
  - 3.2 Market Buyers
  - 3.3 Market Sellers
  - 3.3A Economic Load Response Participants
  - 3.4 Transmission Customers
  - 3.5 Other Control Areas
  - 3.6 Metering Reconciliation
  - 3.7 Inadvertent Interchange
  - 3.8 Market-to-Market Coordination
- 4. [Reserved For Future Use]
- 5. CALCULATION OF CHARGES AND CREDITS FOR TRANSMISSION CONGESTION AND LOSSES
  - 5.1 Transmission Congestion Charge Calculation
  - 5.2 Transmission Congestion Credit Calculation
  - 5.3 Unscheduled Transmission Service (Loop Flow)
  - 5.4 Transmission Loss Charge Calculation
  - 5.5 Distribution of Total Transmission Loss Charges
- 6. “MUST-RUN” FOR RELIABILITY GENERATION
  - 6.1 Introduction
  - 6.2 Identification of Facility Outages
  - 6.3 Dispatch for Local Reliability
  - 6.4 Offer Price Caps
  - 6.5 [Reserved]
  - 6.6 Minimum Generator Operating Parameters – Parameter-Limited Schedules
- 6A [Reserved]
  - 6A.1 [Reserved]
  - 6A.2 [Reserved]
  - 6A.3 [Reserved]
- 7. FINANCIAL TRANSMISSION RIGHTS AUCTIONS

- 7.1 Auctions of Financial Transmission Rights
- 7.1A Long-Term Financial Transmission Rights Auctions
- 7.2 Financial Transmission Rights Characteristics
- 7.3 Auction Procedures
- 7.4 Allocation of Auction Revenues
- 7.5 Simultaneous Feasibility
- 7.6 New Stage 1 Resources
- 7.7 Alternate Stage 1 Resources
- 7.8 Elective Upgrade Auction Revenue Rights
- 7.9 Residual Auction Revenue Rights
- 7.10 Financial Settlement
- 7.11 PJM Settlement as Counterparty
- 8. EMERGENCY AND PRE-EMERGENCY LOAD RESPONSE PROGRAM
  - 8.1 Emergency Load Response and Pre-Emergency Load Response Program Options
  - 8.2 Participant Qualifications
  - 8.3 Metering Requirements
  - 8.4 Registration
  - 8.5 Pre-Emergency Operations
  - 8.6 Emergency Operations
  - 8.7 Verification
  - 8.8 Market Settlements
  - 8.9 Reporting and Compliance
  - 8.10 Non-Hourly Metered Customer Pilot
  - 8.11 Emergency Load Response and Pre-Emergency Load Response Participant Aggregation
- SCHEDULE 2 – COMPONENTS OF COST
- SCHEDULE 2 – EXHIBIT A, EXPLANATION OF THE TREATMENT OF THE COSTS OF EMISSION ALLOWANCES
- SCHEDULE 3 – ALLOCATION OF THE COST AND EXPENSES OF THE OFFICE OF THE INTERCONNECTION
- SCHEDULE 4 – STANDARD FORM OF AGREEMENT TO BECOME A MEMBER OF THE LLC
- SCHEDULE 5 – PJM DISPUTE RESOLUTION PROCEDURES
  - 1. DEFINITIONS
    - 1.1 Alternate Dispute Resolution Committee
    - 1.2 MAAC Dispute Resolution Committee
    - 1.3 Related PJM Agreements
  - 2. PURPOSES AND OBJECTIVES
    - 2.1 Common and Uniform Procedures
    - 2.2 Interpretation
  - 3. NEGOTIATION AND MEDIATION
    - 3.1 When Required
    - 3.2 Procedures
    - 3.3 Costs
  - 4. ARBITRATION
    - 4.1 When Required

- 4.2 Binding Decision
  - 4.3 Initiation
  - 4.4 Selection of Arbitrator(s)
  - 4.5 Procedures
  - 4.6 Summary Disposition and Interim Measures
  - 4.7 Discovery of Facts
  - 4.8 Evidentiary Hearing
  - 4.9 Confidentiality
  - 4.10 Timetable
  - 4.11 Advisory Interpretations
  - 4.12 Decisions
  - 4.13 Costs
  - 4.14 Enforcement
  - 5. ALTERNATE DISPUTE RESOLUTION COMMITTEE
    - 5.1 Membership
    - 5.2 Voting Requirements
    - 5.3 Officers
    - 5.4 Meetings
    - 5.5 Responsibilities
- SCHEDULE 6 – REGIONAL TRANSMISSION EXPANSION  
PLANNING PROTOCOL
- 1. REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL
    - 1.1 Purpose and Objectives
    - 1.2 Conformity with NERC and Other Applicable Criteria
    - 1.3 Establishment of Committees
    - 1.4 Contents of the Regional Transmission Expansion Plan
    - 1.5 Procedure for Development of the Regional Transmission Expansion Plan
    - 1.6 Approval of the Final Regional Transmission Expansion Plan
    - 1.7 Obligation to Build
    - 1.8 Interregional Expansions
    - 1.9 Relationship to the PJM Open Access Transmission Tariff
- SCHEDULE 7 – UNDERFREQUENCY RELAY OBLIGATIONS AND CHARGES
- 1. UNDERFREQUENCY RELAY OBLIGATION
    - 1.1 Application
    - 1.2 Obligations
  - 2. UNDERFREQUENCY RELAY CHARGES
  - 3. DISTRIBUTION OF UNDERFREQUENCY RELAY CHARGES
    - 3.1 Share of Charges
    - 3.2 Allocation by the Office of the Interconnection
- SCHEDULE 8 – DELEGATION OF PJM CONTROL AREA RELIABILITY  
RESPONSIBILITIES
- 1. DELEGATION
  - 2. NEW PARTIES
  - 3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT
- SCHEDULE 9B – PJM SOUTH REGION EMERGENCY PROCEDURE CHARGES
- 1. EMERGENCY PROCEDURE CHARGE

## 2. DISTRIBUTION OF EMERGENCY PROCEDURE CHARGES

2.1 Complying Parties

2.2 All Parties

## SCHEDULE 10 – FORM OF NON-DISCLOSURE AGREEMENT

### 1. DEFINITIONS

1.1 Affected Member

1.2 Authorized Commission

1.3 Authorized Person

1.4 Confidential Information

1.5 FERC

1.6 Information Request.

1.7 Operating Agreement

1.8 Market Monitoring Unit

1.9 PJM Tariff

1.10 Third Party Request.

### 2. Protection of Confidentiality

2.1 Duty to Not Disclose

2.2 Discussion of Confidential Information with Other Authorized Persons

2.3 Defense Against Third Party Requests

2.4 Care and Use of Confidential Information

2.5 Ownership and Privilege

### 3. Remedies

3.1 Material Breach

3.2 Judicial Recourse

3.3 Waiver of Monetary Damages

### 4. Jurisdiction

### 5. Notices

### 6. Severability and Survival

### 7. Representations

### 8. Third Party Beneficiaries

### 9. Counterparts

### 10. Amendment

## SCHEDULE 10A – FORM OF CERTIFICATION

### 1. Definitions

### 2. Requisite Authority

### 3. Protection of Confidential Information

### 4. Defense Against Requests for Disclosure

### 5. Use and Destruction of Confidential Information

### 6. Notice of Disclosure of Confidential Information

### 7. Release of Claims

### 8. Ownership and Privilege

Exhibit A - Certification List of Authorized Persons

## SCHEDULE 11 – ALLOCATION OF COSTS ASSOCIATED WITH NERC

## PENALTY ASSESSMENTS

### 1.1 Purpose and Objectives

### 1.2 Definitions

- 1.3 Allocation of Costs When PJM is the Registered Entity
- 1.4 Allocation of Costs When a PJM Member is the Registered Entity
- 1.5

**SCHEDULE 12 – PJM MEMBER LIST**

**RESOLUTION TO AMEND THE PROCEDURES REQUIRING THE RETENTION OF AN INDEPENDENT CONSULTANT TO PROPOSE A LIST OF CANDIDATES FOR THE BOARD OF MANAGERS ELECTION FOR 2001**

## **Definitions A - B**

### **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, 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 and Tariff, Attachment K-Appendix, section 1.9.4.

### **Act:**

“Act” shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

### **Active and Significant Business Interest:**

“Active and Significant Business Interest” is a term that shall be used to assess the scope of a Member’s PJM membership and shall be based on a Member’s activity in the PJM RTO and/or Interchange Energy Markets. A Member’s Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member’s PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member’s public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member’s recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates’ interests within the PJM footprint.

### **Additional Day-ahead Scheduling Reserves Requirement:**

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

### **Affected Member:**

“Affected Member” shall mean a Member of PJM which as a result of its participation in PJM’s markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

### **Affiliate:**

“Affiliate” shall mean any two or more entities, one of which controls the other or that are under common control. “Control” 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 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.

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

“Agreement,” “Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean this 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 thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

**Annual Meeting of the Members:**

“Annual Meeting of the Members” shall mean the meeting specified in Operating Agreement, section 8.3.1.

**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.

**Associate Member:**

“Associate Member” shall mean an entity that satisfies the requirements of Operating Agreement, section 11.7.

**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 Commission:**

“Authorized Commission” shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

**Authorized Person:**

“Authorized Person” shall have the meaning set forth in Operating Agreement, section 18.17.4.

**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)].

**Base Day-ahead Scheduling Reserves Requirement:**

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

**Batch Load Demand Resource:**

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

**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 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 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.

**Board Member:**

“Board Member” shall mean a member of the PJM Board.

## **Definitions C - D**

### **Capacity Resource:**

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

### **Catastrophic Force Majeure:**

“Catastrophic Force Majeure” shall not include any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, or Curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, unless as a consequence of any such action, event, or combination of events, either (i) all, or substantially all, of the Transmission System is unavailable, or (ii) all, or substantially all, of the interstate natural gas pipeline network, interstate rail, interstate highway or federal waterway transportation network serving the PJM Region is unavailable. The Office of the Interconnection shall determine whether an event of Catastrophic Force Majeure has occurred for purposes of this Agreement, the PJM Tariff, and the Reliability Assurance Agreement, based on an examination of available evidence. The Office of the Interconnection’s determination is subject to review by the Commission.

### **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.

**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, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

**Compliance Monitoring and Enforcement Program:**

“Compliance Monitoring and Enforcement Program” shall mean the program to be used by the NERC and the Regional Entities to monitor, assess and enforce compliance with the NERC Reliability Standards. As part of a Compliance Monitoring and Enforcement Program, NERC and the Regional Entities may, among other things, conduct investigations, determine fault and assess monetary penalties.

**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 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 automatic generation control scheme is applied in order to:

- (a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;
- (d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and
- (e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

**Control Zone:**

“Control Zone” shall mean one Zone or multiple contiguous Zones, as designated in the PJM Manuals.

**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.

**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 this 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 extent that energy serves that Member’s own load.

**Credit Breach:**

“Credit Breach” is the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

**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 Schedule A to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45). 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.

**Curtailed Service Provider:**

“Curtailed 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.

**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 Scheduling Reserves:**

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

**Day-ahead Scheduling Reserves Market:**



“Day-ahead Scheduling Reserves Market” shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

**Day-ahead Scheduling Reserves Requirement:**

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

**Day-ahead Scheduling Reserves Resources:**

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

**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.

**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 Allocation Assessment:**

“Default Allocation Assessment” shall mean the assessment determined pursuant to Operating Agreement, section 15.2.2.

**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 have the meaning provided in the Reliability Assurance Agreement.

**Designated Entity:**

“Designated Entity” shall mean an entity, including an existing Transmission Owner or Nonincumbent Developer, designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, Long-lead Projects, or Economic-based Enhancements or Expansions pursuant to Operating Agreement, Schedule 6, section 1.5.8.

**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.

**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.

**Dynamic Schedule:**

“Dynamic Schedule” shall have the same meaning set forth in the NERC Glossary of Terms Used in NERC Reliability Standards.

**Dynamic Transfer:**

“Dynamic Transfer” shall mean a Pseudo-Tie or Dynamic Schedule.

## **Definitions M - N**

### **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.

### **Market Buyer:**

“Market Buyer” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make purchases in the PJM Interchange Energy Market.

### **Market Monitoring Unit or MMU:**

“Market Monitoring Unit” or “MMU” shall mean 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 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, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant 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 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 Seller:**

“Market Seller” shall mean a Member that has met reasonable creditworthiness standards established by the Office of the Interconnection and that is otherwise able to make sales in the PJM Interchange Energy Market.

**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 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 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 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 mean an entity that satisfies the requirements of Operating Agreement, section 11.6 and that (i) is a member of the LLC immediately prior to the Effective Date, or (ii) has executed an Additional Member Agreement in the form set forth in Operating Agreement, Schedule 4.

**Members Committee:**

“Members Committee” shall mean the committee specified in Operating Agreement, section 8, composed of representatives of all the Members.

**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 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 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, and the last generator breaker opening as measured by PJM’s State Estimator.

**MISO:**

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

**Multi-Driver Project:**

“Multi-Driver Project” shall mean a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives.

**NERC:**

“NERC” shall mean the North American Electric Reliability Corporation, or any successor thereto.

**NERC Functional Model:**

“NERC Functional Model” shall be the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

**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.

**NERC Reliability Standards:**

“NERC Reliability Standards” shall mean those standards that have been developed by NERC and approved by FERC to ensure the reliability of the electric bulk power system.

**NERC Rules of Procedure:**“NERC Rules of Procedure” shall be the rules and procedures developed by NERC and approved by the FERC. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as the Registered Entity.

**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.

**Network Resource:**

“Network Resource” shall have the meaning specified in the PJM Tariff.

**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.

**New York ISO or NYISO:**

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

**No-load Cost:**

“No-load Cost” shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

**Non-Disclosure Agreement:**

“Non-Disclosure Agreement” shall mean an agreement between an Authorized Person and the Office of the Interconnection, pursuant to Operating Agreement, section, the form of which is appended to this Agreement as Operating Agreement, Schedule 10, wherein the Authorized Person is given access to otherwise restricted confidential information, for the benefit of their respective Authorized Commission.

**Nonincumbent Developer:**

“Nonincumbent Developer” shall mean: (1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J.

**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, and 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, 1.5A.6.



**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.

## **1.10 Scheduling.**

### **1.10.1 General.**

- (a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.
- (b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.
- (c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.
- (d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

#### **1.10.1A Day-ahead Energy Market Scheduling.**

The following actions shall occur not later than 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

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

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection:

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

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified

in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

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

(c-2) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the

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

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.
- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional,

but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d), and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;
- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour,

or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour; and
- ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant, an Emergency Load Response participant, or a Pre-Emergency Load Response participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour; and
- x) Shall not exceed an energy offer price of \$0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

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

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and
- iii. An adder of up to \$12.00 per megawatt of Regulation provided applied to the capability offer.

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

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

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

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

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance



problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

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

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Demand Resource. The submission of demand reduction bids for Demand Resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. A Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead

Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Demand Resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

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

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

#### **1.10.1B Demand Bid Scheduling and Screening**

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

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids

submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

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

Where:

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

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

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

### **1.10.2 Pool-scheduled Resources.**

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

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in

Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

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

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

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

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

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

### **1.10.3 Self-scheduled Resources.**

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

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

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

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

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

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

#### **1.10.4 Capacity Resources.**

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

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

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

#### **1.10.5 External Resources.**

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall

be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

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

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

#### **1.10.6 External Market Buyers.**

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

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

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

#### **1.10.6A Transmission Loading Relief Customers.**

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

- (i) enter its election on OASIS by 10:30 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and
- (ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

#### **1.10.7 Bilateral Transactions.**

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

#### **1.10.8 Office of the Interconnection Responsibilities.**

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv)

the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

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

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection



(b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

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

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

#### **1.10.9 Hourly Scheduling.**

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the

results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or
- iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

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

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

External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

### **1.10.9A Updating Offers in Real-time**

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

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

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

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

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

### **1.10.9B Offer Parameter Flexibility**

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

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

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

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

### 3.8 Market-to-Market Coordination

The Office of the Interconnection shall charge or credit a Market Participant for the transmission congestion from the Market Participant's Pseudo-Tie generator within MISO to the PJM-MISO interface resulting from market-to-market coordination pursuant to this Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8. The Office of the Interconnection shall calculate such charges and credits for the Real-time Energy Market for each Pseudo-Tie generator using the following formulas.

$$RT\ Charge / Credit_{PT} = RT\ CLMP_{PT} * DevMW_{PT}$$

Where:

$$RTCLMP_{PT} = \sum RT\ ShadowPrice_{FG} * (RT\ ShiftFactor_{FG,PT} - RT\ ShiftFactor_{FG,Interface})$$

$$RTCLMP_{PT} =$$

Real-time congestion LMP for the path from the Pseudo-Tie generator to the MISO-PJM common interface.

$$RT\ ShadowPrice_{FG} =$$

Real-time shadow price for each M2M Flowgate calculated in accordance with the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

$$RT\ ShiftFactor_{FG,PT} =$$

Real-time shift factor for the Pseudo-Tie generator and each M2M Flowgate.

Where:

$$DevMW_{PT} = (RT\ MW_{PT} - DA\ MW_{PT})$$

$$DevMW_{PT} =$$

The megawatt deviation between the cleared megawatts in the Day-ahead Energy Market and Real-time Energy Market megawatt output for a Pseudo-Tie generator.

$$RT\ MW_{PT} =$$

Real-time Energy Market megawatt output for the Pseudo-Tie generator.

$$DA\ MW_{PT} =$$

Cleared and committed megawatts for a Pseudo-Tie generator in the Day-ahead Energy Market.

The dollars refunded to or collected from the Pseudo-Tie generator will be, respectively, distributed from or added to the Balancing Congestion Charges fund.