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February 5, 2026

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

Re: PJM Interconnection, L.L.C., Docket No. ER22-2359-005, Tariff Records Clean Up

Dear Secretary Reese:

On February 2, 2026, PJM Interconnection, L.L.C. (PJM) notified the Commission that March 4, 2026, would be the effective date for Order No. 881 implementation including related amendments to the Tariff, including the new Attachment W, and Operating Agreement, consistent with the revisions noted in the February 2, 2025 informational filing.¹ PJM acknowledges that the Transmission Owners separately filed related amendments to the Consolidated Transmission Owners Agreement, consistent with this March 4, 2026 effective date.² Pursuant to PJM's February 2, 2026 informational filing, this clean-up filing establishes the new tariff record effective date.

II. COMMUNICATIONS

PJM requests that all communications regarding this filing be directed to the following persons:

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¹ *PJM Interconnection, L.L.C., Informational Filing Providing Precise Effective Date for Order No. 881 Implementation, Docket No. ER22-2359-000 (February 2, 2026).*

² *East Kentucky Power Cooperative, Inc., Tariff Records Clean Up, Docket No. ER23-2964-001 (February 5, 2026)*

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III. DOCUMENTS INCLUDED WITH THIS FILING

PJM hereby submits an eTariff XML filing package consisting of the following materials:

1. This transmittal letter; and
2. Attachment A – Revisions to the Tariff and OA, in clean format.

IV. CONCLUSION

PJM has served a copy of this filing on all members and state utilities in the PJM Region. In accordance with the Commission's regulations,³ PJM will post a copy of this filing to the FERC filings section, located at the following link: <https://www.pjm.com/library/filing-order>.

Respectfully submitted,

/s/ Erin Lai

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

Attachment A

Revisions to the PJM Open Access Transmission Tariff

and

PJM Operating Agreement

(Clean Format)

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- 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
 - 5.6 Transmission Constraint Penalty Factors
- 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

List of Transmission Owners

ATTACHMENT M

PJM Market Monitoring Plan

ATTACHMENT M – APPENDIX

PJM Market Monitor Plan Attachment M Appendix

- 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

ATTACHMENT M-1 (FirstEnergy)

Energy Procedure Manual for Determining Supplier Total Hourly Energy Obligation

ATTACHMENT M-2 (First Energy)

**Energy Procedure Manual for Determining Supplier Peak Load Share
Procedures for Load Determination**

ATTACHMENT M-2 (ComEd)

**Determination of Capacity Peak Load Contributions and Network Service Peak Load
Contributions**

ATTACHMENT M-2 (PSE&G)

**Procedures for Determination of Peak Load Contributions and Hourly Load
Obligations for Retail Customers**

ATTACHMENT M-2 (Atlantic City Electric Company)

**Procedures for Determination of Peak Load Contributions and Hourly Load
Obligations for Retail Customers**

ATTACHMENT M-2 (Delmarva Power & Light Company)

**Procedures for Determination of Peak Load Contributions and Hourly Load
Obligations for Retail Customers**

ATTACHMENT M-2 (Delmarva Power & Light Company)

**Procedures for Determination of Peak Load Contributions and Hourly Load
Obligations for Retail Customers**

ATTACHMENT M-2 (Duke Energy Ohio, Inc.)

**Procedures for Determination of Peak Load Contributions, Network Service Peak
Load and Hourly Load Obligations for Retail Customers**

ATTACHMENT M-3

Additional Procedures for Planning of Supplemental Projects

ATTACHMENT N

Form of Generation Interconnection Feasibility Study Agreement

ATTACHMENT N-1

Form of System Impact Study Agreement

ATTACHMENT N-2

Form of Facilities Study Agreement

ATTACHMENT N-3

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

- 1 Interconnection Service**
 - 1.1 Commencement Date
 - 1.2 Conditions Precedent
 - 1.3 Term
 - 1.4 Initial Operation
 - 1.4A Other Interconnection Options
 - 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
- 23 Representations And Warranties**
- 23.1 General
- 24 Tax Liability**
- 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

ATTACHMENT O - SCHEDULE A

Customer Facility Location/Site Plan

ATTACHMENT O - SCHEDULE B

Single-Line Diagram

ATTACHMENT O - SCHEDULE C

List of Metering Equipment

ATTACHMENT O - SCHEDULE D

Applicable Technical Requirements and Standards

ATTACHMENT O - SCHEDULE E

Schedule of Charges

ATTACHMENT O - SCHEDULE F

Schedule of Non-Standard Terms & Conditions

ATTACHMENT O - SCHEDULE G

Interconnection Customer's Agreement to Conform with IRS Safe Harbor

Provisions for Non-Taxable Status

ATTACHMENT O - SCHEDULE H

Interconnection Requirements for a Wind Generation Facility

ATTACHMENT O – SCHEDULE I

Interconnection Specifications for an Energy Storage Resource

ATTACHMENT O – SCHEDULE J

Schedule of Terms and Conditions for Surplus Interconnection Service

ATTACHMENT O – SCHEDULE K

Requirements for Interconnection Service Below Full Electrical Generating Capability

ATTACHMENT O-1

Form of Interim Interconnection Service Agreement

ATTACHMENT O-2

Form of Network Upgrade Funding Agreement

ATTACHMENT P

Form of Interconnection Construction Service Agreement

- 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
- 6 Warranties**
 - 6.1 Interconnection Customer Warranty
 - 6.2 Manufacturer Warranties
- 7 [Reserved.]**
- 8 [Reserved.]**
- 9 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 Assignment**
 - 10.1 Assignment with Prior Consent
 - 10.2 Assignment Without Prior Consent
 - 10.3 Successors and Assigns
- 11 Insurance**
 - 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
- 12 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	Breach, Cure And Default
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
14	Termination
14.1	Termination
14.2	[Reserved.]
14.3	Cancellation By Interconnection Customer
14.4	Survival of Rights
15	Force Majeure
15.1	Notice
15.2	Duration of Force Majeure
15.3	Obligation to Make Payments
15.4	Definition of Force Majeure
16	Subcontractors
16.1	Use of Subcontractors
16.2	Responsibility of Principal
16.3	Indemnification by Subcontractors
16.4	Subcontractors Not Beneficiaries
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 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
18	Information Access And Audit Rights
18.1	Information Access
18.2	Reporting of Non-Force Majeure Events
18.3	Audit Rights
19	Disputes

- 19.1 Submission
- 19.2 Rights Under The Federal Power Act
- 19.3 Equitable Remedies
- 20 Notices**
 - 20.1 General
 - 20.2 Operational Contacts
- 21 Miscellaneous**
 - 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
- 22 Representations and Warranties**
 - 22.1 General

ATTACHMENT P - SCHEDULE A

Site Plan

ATTACHMENT P - SCHEDULE B

Single-Line Diagram of Interconnection Facilities

ATTACHMENT P - SCHEDULE C

Transmission Owner Interconnection Facilities to be Built by Interconnected Transmission Owner

ATTACHMENT P - SCHEDULE D

Transmission Owner Interconnection Facilities to be Built by Interconnection Customer Pursuant to Option to Build

ATTACHMENT P - SCHEDULE E

Merchant Network Upgrades to be Built by Interconnected Transmission Owner

ATTACHMENT P - SCHEDULE F

Merchant Network Upgrades to be Built by Interconnection Customer Pursuant to Option to Build

ATTACHMENT P - SCHEDULE G

Customer Interconnection Facilities

ATTACHMENT P - SCHEDULE H

Negotiated Contract Option Terms

ATTACHMENT P - SCHEDULE I

Scope of Work

ATTACHMENT P - SCHEDULE J

Schedule of Work

ATTACHMENT P - SCHEDULE K

Applicable Technical Requirements and Standards

ATTACHMENT P - SCHEDULE L

Interconnection Customer's Agreement to Confirm with IRS Safe Harbor

Provisions For Non-Taxable Status

ATTACHMENT P - SCHEDULE M

Schedule of Non-Standard Terms and Conditions

ATTACHMENT P - SCHEDULE N

Interconnection Requirements for a Wind Generation Facility

ATTACHMENT Q

PJM Credit Policy

ATTACHMENT R

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

ATTACHMENT S

Form of Transmission Interconnection Feasibility Study Agreement

ATTACHMENT T

Identification of Merchant Transmission Facilities

ATTACHMENT U

Independent Transmission Companies

ATTACHMENT V

Form of ITC Agreement

ATTACHMENT W

Thermal Transmission Facility Ratings

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**

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- 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
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- 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
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- 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

30-minute Reserve:

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

30-minute Reserve Requirement:

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

Abnormal Condition:

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

Acceleration Request:

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

Affected System:

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

Affected System Operator:

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

Affiliate:

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

Agreements:

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

Ambient-Adjusted Rating:

“Ambient-Adjusted Rating” (AAR) shall mean a Transmission Facility Rating that:

- (a) Applies to a time period of not greater than one hour.
- (b) Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.
- (c) Reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently.
- (d) Is evaluated at least each hour, if not more frequently.

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, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

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

Attachment Facilities:

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

Attachment H:

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

Auction Revenue Rights:

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

Auction Revenue Rights Credits:

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

Authorized Government Agency:

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

Avoidable Cost Rate:

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

Balancing Congestion Charges:

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

Balancing Ratio:

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

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Demand Resource Constraint:

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount,

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

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

Base Capacity 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 Load Generation Resource

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

Base Offer Segment:

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

Base Residual Auction:

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

Batch Load Economic Load Response Participant Resource:

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

Behind The Meter Generation:

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

Black Start Service:

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

Border Yearly Charge:

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

Breach:

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

Breaching Party:

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

Business Day:

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

Buy Bid:

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

Buyer-Side Market Power:

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

Definitions – E - F

Economic-based Enhancement or Expansion:

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

Economic Load Response Participant:

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

Economic Maximum:

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

Economic Minimum:

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

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:

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

Electrical Distance:

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

Eligible Customer:

“Eligible Customer” shall mean:

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

Eligible Fast-Start Resource:

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

Emergency Action:

“Emergency Action” shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

Emergency Condition:

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

Emergency Load Response Program:

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

Emergency Rating:

“Emergency Rating” shall mean a Transmission Facility Rating that reflects operation for a specified, finite period, rather than reflecting continuous operation. An Emergency Rating may assume an acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Energy Efficiency Resource:

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

Energy Market Opportunity Cost:

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

Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

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

Energy Settlement Area:

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

Energy Storage Resource:

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

Energy Storage Resource Model Participant:

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

Energy Storage Resource Participation Model:

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

Energy Transmission Injection Rights:

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

Entity Providing Supply Services to Default Retail Service Provider:

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

Environmental Laws:

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

Environmentally-Limited Resource:

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

Equivalent Load:

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

Event of Default:

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

Exercise of Buyer-Side Market Power:

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

Existing Generation Capacity Resource:

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

Export Credit Exposure:

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

Export Nodal Reference Price:

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

Export Transaction:

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

Export Transaction Price Factor:

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

Export Transaction Screening:

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

Export Transactions Net Activity:

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

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under

emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Summer Demand Resource:

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

Extended Summer Resource Price Adder:

“Extended Summer Resource Price Adder” shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

Extended Synchronized Reserve Requirement:

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

Extended 30-minute Reserve Requirement:

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

External Market Buyer:

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

External Resource:

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

Facilities Study:

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses

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

Fast-Start Resource:

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

Federal Power Act:

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

FERC or Commission:

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

FERC Market Rules:

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

Final Offer:

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

Final RTO Unforced Capacity Obligation:

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

Financial Close:

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

Financial Default:

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

Financial Transmission Right:

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

Financial Transmission Right Obligation:

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

Financial Transmission Right Option:

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

Firm Point-To-Point Transmission Service:

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

Firm Transmission Feasibility Study:

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

Firm Transmission Withdrawal Rights:

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

First Incremental Auction:

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

Flexible Resource:

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

Forecast Pool Requirement:

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

Foreign Guaranty:

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

Form 715 Planning Criteria:

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

Forward Daily Natural Gas Prices:

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

Forward Hourly Ancillary Services Prices:

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

Forward Hourly LMPs:

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

FTR Credit Limit:

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

FTR Credit Requirement:

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

FTR Flow Undiversified:

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

FTR Historical Value:

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

FTR Holder:

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

FTR Monthly Credit Requirement Contribution:

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

FTR Net Activity:

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

FTR Participant:

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

FTR Portfolio Auction Value:

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

Fuel Cost Policy:

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

Full Notice to Proceed:

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

Definitions – L – M – N

Legacy Policy:

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

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

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

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

Limited Resource Constraint:

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

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 Interest:

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

Load Management:

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

Load Management Event:

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

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

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

Load Serving Charging Energy:

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

Load Serving Entity (LSE):

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

Load Shedding:

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

Local Upgrades:

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

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

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

Location:

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

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind 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 *reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve* assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind 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.

Marginal Value:

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

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

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

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

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

Market Operations Center:

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

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, 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 Revenue Neutrality Offset:

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

Market Seller Offer Cap:

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

Market 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.

Mixed Technology Facility:

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

MOPR Floor Offer Price:

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

Multi-Driver Project:

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

Native Load Customers:

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

Near-Term Transmission Service:

“Near-Term Transmission Service” shall mean Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date. “Near-Term Transmission Service” includes any Point-To-Point Transmission Service and Network Integration Transmission Service where the start and end date of the designation or request is within the next 10 days.

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, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load

but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

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

Network Operating Committee:

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

Network Resource:

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

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

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

Network Upgrades:

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

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

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

Neutral Party:

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

New Entry Capacity Resource with State Subsidy:

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

New PJM Zone(s):

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

New Service Customers:

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

New Service Request:

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

New Services Queue:

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

New York ISO or NYISO:

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

Nodal Reference Price:

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

No-load Cost:

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

Nominal Rated Capability:

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

Nominated Demand Resource Value:

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

Nominated Energy Efficiency Value:

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

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

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

Non-Firm Sale:

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

Non-Firm Transmission Withdrawal Rights:

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

Non-Performance Charge:

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

Nonincumbent Developer:

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

Non-Regulatory Opportunity Cost:

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

Non-Retail Behind The Meter Generation:

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

Non-Synchronized Reserve:

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

Non-Synchronized Reserve Event:

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

Non-Variable Loads:

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

Non-Zone Network Load:

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

Normal Maximum Generation:

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

Normal Minimum Generation:

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

Definitions – R - S

Ramping Capability:

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

Real-time Congestion Price:

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

Real-time Loss Price:

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

Real-time Energy Market:

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

Real-time Offer:

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

Real-time Prices:

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

Real-time Settlement Interval:

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

Real-time System Energy Price:

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

Reasonable Efforts:

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

Receiving Party:

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

Referral:

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

Reference Resource:

“Reference Resource” shall mean a combustion turbine generating station, configured with a single General Electric Frame 7HA turbine with evaporative cooling, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 9.134 Mmbtu/MWh.

Regional Entity:

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

Regional Transmission Expansion Plan:

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

Regional Transmission Group (RTG):

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

Regulation:

“Regulation” shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to separately increase and

decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:

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

Relevant Electric Retail Regulatory Authority:

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

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:

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

Reliability Pricing Model Auction:

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

Required Transmission Enhancements:

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

Reserved Capacity:

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

Reserve Penalty Factor:

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

Reserve Sub-zone:

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

Reserve Zone:

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

Residual Auction Revenue Rights:

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

Residual Metered Load:

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

Resource Substitution Charge:

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

Revenue Data for Settlements:

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

RPM Seller Credit:

“RPM Seller Credit” shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:

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

Schedule of Work:

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

Scope of Work:

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

Seasonal Capacity Performance Resource:

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

Seasonal Facility Rating:

“Seasonal Facility Rating” shall mean a Transmission Facility Rating that:

(a) Applies to a specified season, where seasons are defined by the Office of the Interconnection to include not fewer than four seasons in each year, and to reasonably reflect portions of the year where expected high temperatures are relatively consistent.

(b) Reflects an up-to-date forecast of ambient air temperature across the relevant season over which the rating applies.

(c) Is evaluated annually, if not more frequently, for each season in the future for which Transmission Service can be requested

Secondary Reserve:

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

Secondary Systems:

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

Second Incremental Auction:

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

Security:

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

Segment:

“Segment” shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:

“Self-Supply” shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual

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

Self-Supply Entity:

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

Self-Supply Seller:

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

Sell Offer:

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

Service Agreement:

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

Service Commencement Date:

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

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

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

Short-term Project:

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

Short-Term Resource Procurement Target:

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

Short-Term Resource Procurement Target Applicable Share:

“Short-Term Resource Procurement Target Applicable Share” shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

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

Small Commercial Customer:

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

Small Generation Resource:

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

Small Inverter Facility:

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

Small Inverter ISA:

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

Special Member:

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

Spot Market Backup:

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

Spot Market Energy:

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

Start Additional Labor Costs:

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

Start Fuel:

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

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

- Cold Soak Time = $0.73 * \text{unit specific Minimum Run Time (in hours)}$
- Intermediate Soak Time = $0.61 * \text{unit specific Minimum Run Time (in hours)}$
- Hot Soak Time = $0.43 * \text{unit specific Minimum Run Time (in hours)}$

Start-Up Costs:

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

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), “Start Fuel” is fuel consumed from first fire of start process (initial reactor criticality for nuclear units): Start-Up Costs shall mean the net unit costs from PJM’s notification to the level at which the unit can follow PJM’s dispatch, and from last breaker open to shutdown.

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

State:

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

State Commission:

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

State Estimator:

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

State Subsidy:

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

- (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or
- (2) will support the construction, development, or operation of a new or existing Capacity Resource; or
- (3) could have the effect of allowing the unit to clear in any PJM capacity auction.

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

development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

- (i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);
- (ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and
- (iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

State of Charge:

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

State of Charge Management:

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

Station Power:

“Station Power” shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i)

used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-Annual Resource Constraint:

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

Sub-Annual Resource Price Decrement:

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

Sub-Annual Resource Reliability Target:

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

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through

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

Sub-meter:

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

Summer-Period Capacity Performance Resource:

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

Surplus Interconnection Customer:

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

Surplus Interconnection Request:

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

Surplus Interconnection Service:

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

Switching and Tagging Rules:

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

Synchronized Reserve:

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

Synchronized Reserve Event:

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

Synchronized Reserve Requirement:

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

System Condition:

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

System Energy Price:

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

System Impact Study:

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

System Protection Facilities:

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

Definitions – T – U - V

Tangible Net Worth:

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

Target Allocation:

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

Third Incremental Auction:

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

Third-Party Sale:

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

Tie Line:

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

Total Lost Opportunity Cost Offer:

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

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

Total Net Obligation:

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

Total Net Sell Position:

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

Total Operating Reserve Offer:

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

Trade Reference:

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

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement,

Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

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

Transmission Constraint Penalty Factor:

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

Transmission Customer:

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

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

Transmission Facilities:

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

Transmission Facility Rating:

“Transmission Facility Rating” shall mean the maximum transfer capability, or the maximum or minimum voltage, current, frequency, or real or reactive power flow, through a Transmission Facility that does not violate the applicable rating of relevant transmission equipment.

Transmission Facility Ratings are computed in accordance with a written Transmission Facility Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers. Transmission Facility Ratings also encompass AARs, AAR Exceptions, and Temporary Conditional Transmission Facility Ratings.

Transmission Forced Outage:

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

Transmission Injection Rights:

“Transmission Injection Rights” shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

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

Transmission Interconnection Facilities Study:

“Transmission Interconnection Facilities Study” shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

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

Transmission Interconnection Request:

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

Transmission Loading Relief:

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

Transmission Loss Charge:

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

Transmission Owner:

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

Transmission Owner Attachment Facilities:

“Transmission Owner Attachment Facilities” shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner’s side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

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

Transmission Owner Upgrade:

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

Transmission Planned Outage:

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

Transmission Provider:

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

- (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
- (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and
- (c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider’s Monthly Transmission System Peak:

“Transmission Provider’s Monthly Transmission System Peak” shall mean the maximum firm usage of the Transmission Provider’s Transmission System in a calendar month.

Transmission Service:

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

Transmission Service Request:

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

Transmission System:

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

Transmission Withdrawal Rights:

“Transmission Withdrawal Rights” shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

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

Unforced Capacity:

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

Unsecured Credit:

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

Unsecured Credit Allowance:

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

Updated VRR Curve:

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

Updated VRR Curve Decrement:

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

Updated VRR Curve Increment:

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

Upgrade Construction Service Agreement:

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

Upgrade Customer:

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

Upgrade Feasibility Study:

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

Upgrade-Related Rights:

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

Upgrade Request:

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

Up-to Congestion Counterflow Transaction:

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

Up-to Congestion Historical Month:

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

Up-to Congestion Prevailing Flow Transaction:

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

Up-to Congestion Reference Price:

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

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

Up-to Congestion Transaction:

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

Variable Loads:

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

Variable Resource Requirement Curve:

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

Virtual Credit Exposure:

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

Virtual Transaction:

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

Virtual Transaction Screening:

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

Virtual Transactions Net Activity:

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

Voltage Reduction Action:

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

Voltage Reduction Alert:

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

Voltage Reduction Warning:

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

1.9 Prescheduling.

The following procedures and principles shall govern the prescheduling activities necessary to plan for the reliable operation of the PJM Region and for the efficient operation of the PJM Interchange Energy Market.

1.9.1 Outage Scheduling.

The Office of the Interconnection shall be responsible for coordinating and approving requests for outages of generation and transmission facilities as necessary for the reliable operation of the PJM Region, in accordance with the PJM Manuals. The Office of the Interconnection shall maintain records of outages and outage requests of these facilities.

1.9.2 Planned Outages.

(a) A Generator Planned Outage shall be included in Generator Planned Outage schedules established prior to the scheduled start date for the outage, in accordance with standards and procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall conduct Generator Planned Outage scheduling for Generation Capacity Resources in accordance with the Reliability Assurance Agreement and the PJM Manuals and in consultation with the Market Sellers owning or controlling the output of such resources. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from all or part of a generation resource undergoing an approved Generator Planned Outage. If the Office of the Interconnection determines that approval of a Generator Planned Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval or withdraw a prior approval. Approval of a Generator Planned Outage of a Generation Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. The Market Seller shall provide the Office of the Interconnection with an estimate of the amount of time it needs to return to service any Generation Capacity Resource on Generator Planned Outage that is already underway. If the Office of the Interconnection withdraws its approval of a Generator Planned Outage, it shall coordinate with the Market Seller owning or controlling the resource to reschedule the Generator Planned Outage at the earliest practical time. The Office of the Interconnection shall if possible propose alternative schedules with the intent of minimizing the economic impact on the Market Seller of a Generator Planned Outage.

(c) The Office of the Interconnection shall conduct Transmission Planned Outage scheduling in accordance with procedures specified in the Consolidated Transmission Owners Agreement and the PJM Manuals, and in accordance with the following procedures:

(i) Transmission Owners shall use reasonable efforts to submit Transmission Planned Outage schedules one year in advance but by no later than the first of the month six months in advance of the requested start date for all outages that are expected to exceed

five working days duration, with regular (at least monthly) updates as new information becomes available.

(ii) If notice of a Transmission Planned Outage is not provided in accordance with the requirements in subsection (i) above, and if such outage is determined by the Office of the Interconnection to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid such impacts. The Office of the Interconnection may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under the Operating Agreement or PJM Tariff and provided the Office of the Interconnection determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had the Office of the Interconnection implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. The Office of the Interconnection may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from the Office of the Interconnection's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in the Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.

(iii) Transmission Owners shall submit notice of all Transmission Planned Outages to the Office of the Interconnection by the first day of the month preceding the month the outage will commence, with updates as new information becomes available.

(iv) If notice of a Transmission Planned Outage is not provided by the first day of the month preceding the month the outage will commence, and if such outage is determined by the Office of the Interconnection to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid such impacts. The Office of the Interconnection shall perform this analysis and notify the Transmission Owner in a timely manner if it will require rescheduling of the outage. The Office of the Interconnection may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under the Operating Agreement or PJM Tariff and provided the Office of the Interconnection determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had the Office of the Interconnection implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. The Office of the Interconnection may, at the Transmission Owner's

consent, directly assign to the Transmission Owner all generation and other costs resulting from the Office of the Interconnection's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in the Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.

(v) The Office of the Interconnection reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure reliable system operations on a case by case basis regardless of duration or date of submission.

(vi) The Office of the Interconnection shall post notice of Transmission Planned Outages on OASIS upon receipt of such notice from the Transmission Owner; provided, however, that the Office of the Interconnection shall not post on OASIS notice of any component of a Transmission Planned Outage to the extent such component shall directly reveal a generator outage. In such cases, the Transmission Owner, in addition to providing notice to the Office of the Interconnection as required above, concurrently shall inform the affected Generation Owner of such outage, limiting such communication to that necessary to describe the outage and to coordinate with the Generation Owner on matters of safety to persons, facilities, and equipment. The Transmission Owner shall not notify any other Market Participant of such outage and shall arrange any other necessary coordination through the Office of the Interconnection.

In addition, if the Office of the Interconnection determines that transmission maintenance schedules proposed by one or more Members would significantly affect the efficient and reliable operation of the PJM Region, the Office of the Interconnection may establish alternative schedules, but such alternative shall minimize the economic impact on the Member or Members whose maintenance schedules the Office of the Interconnection proposes to modify.

(d) The Office of the Interconnection shall coordinate resolution of outage or other planning conflicts that may give rise to unreliable system conditions. The Members shall comply with all maintenance schedules established by the Office of the Interconnection.

1.9.3 Generator Maintenance Outages.

(a) A Generator Maintenance Outage may only be scheduled if approved by the Office of the Interconnection prior to the requested start date for the outage, in accordance with subsection (b) hereof and the standards and procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall schedule Generator Maintenance Outages for Generation Capacity Resources in accordance with the procedures specified in the PJM Manuals and in consultation with the Market Seller owning or controlling the output of such resources. The Office of the Interconnection shall approve requests for Generator Maintenance Outages for such a Generation Capacity Resource unless the outage would threaten the adequacy of reserves in, or the reliability of, the PJM Region. A Market Participant shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from a

generation resource undergoing an approved full or partial Generator Maintenance Outage. If the Office of the Interconnection determines that approval of a Generator Maintenance Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval, withdraw a prior approval, or rescind a prior approval of a Generator Maintenance Outage that is already underway. Approval of a Generator Maintenance Outage of a Generation Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. In addition, if the Office of the Interconnection determines that it must rescind its approval of a Generator Maintenance Outage that is already underway in order to preserve the reliable operation of the PJM Region, the Office of the Interconnection will provide the Market Seller of the Generation Capacity Resource at least 72 hours' notice thereof. The Market Seller shall be required to make the Generation Capacity Resource available for normal operation within 72 hours of such notice. If the generator is not made available for normal operation by 72 hours after the notice of the rescission of the approval of the Generator Maintenance Outage, for the remaining time the resource continues on the outage it shall be deemed to have experienced a Generator Forced Outage. If the Office of the Interconnection withholds, withdraws or rescinds approval of a Generator Maintenance Outage, it shall coordinate with the Market Seller owning or controlling the resource to reschedule the Generator Maintenance Outage at the earliest practical time. The Office of the Interconnection shall, if possible, propose alternative schedules with the intent of minimizing the economic impact on the Market Seller of a Generator Maintenance Outage.

1.9.4 Forced Outages.

(a) Each Market Seller that owns or controls a pool-scheduled resource, or Generation Capacity Resource whether or not pool-scheduled, shall: (i) advise the Office of the Interconnection of a Generator Forced Outage suffered or anticipated to be suffered by any such resource as promptly as possible; (ii) provide the Office of the Interconnection with the expected date and time that the resource will be made available; and (iii) make a record of the events and circumstances giving rise to the Generator Forced Outage. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or satisfy delivery obligations, from a generation resource undergoing a Generator Forced Outage. A Generation Capacity Resource committed to PJM loads through an RPM Auction, FRR Capacity Plan, or by designation as a replacement resource under Attachment DD of the PJM Tariff, that does not deliver all or part of its scheduled energy shall be deemed to have experienced a Generator Forced Outage with respect to such undelivered energy, in accordance with standards and procedures for full and partial Generator Forced Outages specified in the Reliability Assurance Agreement, and the PJM Manuals.

(b) The Office of the Interconnection shall receive notification of Forced Transmission Outages, and information on the return to service, of Transmission Facilities in the PJM Region in accordance with standards and procedures specified in, as applicable, the Consolidated Transmission Owners Agreement and the PJM Manuals.

1.9.4A Transmission Outage Acceleration.

(a) Planned Transmission Outages and Forced Transmission Outages otherwise scheduled pursuant to sections 1.9.2 and 1.9.4 respectively of this Schedule may be accelerated or rescheduled at the request of a Generation Owner or other Market Participant in accordance with the terms and conditions of this section 1.9.4A and the PJM Manuals.

(b) Transmission Outages Requiring Coordination With A Specific Generation Owner.

(i) Receipt of Acceleration Request. Prior to a scheduled Planned Transmission Outage associated with the interconnection of a generating unit to the Transmission System, the affected Generation Owner may request that the outage be accelerated or rescheduled.

Such Acceleration Request shall be submitted to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals.

(ii) Determination to Accommodate Acceleration Request. Upon receipt of an Acceleration Request, the Office of the Interconnection shall notify the affected Transmission Owner of such Acceleration Request. The affected Transmission Owner shall determine, in its sole discretion, whether to accelerate or reschedule a transmission outage. In making this determination, the affected Transmission Owner shall follow Good Utility Practice, applicable Occupational Safety and Health Administration standards, and applicable company safety standards, and shall consider any requirements contained in pertinent collective bargaining agreements. In the event that the affected Transmission Owner determines to accelerate or reschedule a transmission outage, it shall provide the Office of the Interconnection, within the time set forth in the PJM Manuals, an estimate of the cost to accelerate or reschedule the transmission outage and the revised schedule for the transmission outage (“Acceleration Estimate”).

(iii) Provision of Acceleration Estimate. Upon receipt of the Acceleration Estimate and verification that the Generation Owner has met reasonable creditworthiness standards established by the Office of the Interconnection, the Office of the Interconnection shall provide the Generation Owner with the Acceleration Estimate. In the event that the Generation Owner does not meet the creditworthiness standard, the Office of the Interconnection shall not provide the Acceleration Estimate and the transmission outage shall not be accelerated or rescheduled. Upon receipt of the Acceleration Estimate, the Generation Owner, within the time period specified in the PJM Manuals, shall notify the Office of the Interconnection as to whether it desires to accelerate or reschedule the transmission outage pursuant to the terms of the Acceleration Estimate.

(iv) Cost Responsibility. In the event the Generation Owner notifies the Office of the Interconnection that it desires to proceed with the acceleration or rescheduling of the transmission outage pursuant to section 1.9.4A(a)(iii), the Generation Owner shall be solely responsible for actual costs incurred by the affected Transmission Owner for the acceleration or rescheduling of the transmission outage. The Generation Owner's cost responsibility is not relieved, if, despite the good faith efforts of the Transmission Owner, the amount of costs set forth in the Acceleration Estimate is exceeded by less than 20

percent, or the Transmission Owner is unable successfully to complete the outage pursuant to the revised schedule set forth in the Acceleration Estimate. Prior to incurring costs exceeding 120 percent of the cost estimate set forth in the Acceleration Estimate, the affected Transmission Owner shall advise the Office of the Interconnection of such increase, and the Office of the Interconnection then shall notify the Generation Owner. After receipt of such notification, within the time period set forth in the PJM Manuals, the Generation Owner shall inform the Office of the Interconnection whether it desires to continue with the revised transmission outage schedule and pay the additional costs. The Office of the Interconnection shall notify the affected Transmission Owner of the Generation Owner's decision. In the event the Generation Owner desires not to proceed, the transmission outage shall occur according to normal work practices and the Generation Owner shall be responsible for all incurred costs and committed costs and obligations of the affected Transmission Owner for the acceleration or rescheduling of the transmission outage as of the date that the affected Transmission Owner notified the Office of the Interconnection of the increase in costs.

(c) Transmission Outages That Could Cause Congestion Revenue Inadequacy.

(i) Posting of Transmission Outage. In the event that the Office of the Interconnection determines that a Planned Transmission Outage or Forced Transmission Outage could exceed five days and could cause congestion revenue inadequacy in excess of \$500,000, the Office of the Interconnection shall post a notice of such transmission outage on its internet site. Within the time period and pursuant to the procedures set forth in the PJM Manuals, any Market Participant may request that such transmission outage be accelerated or rescheduled.

(ii) Determination to Accelerate or Reschedule Transmission Outage. Upon receipt of the Acceleration Request(s) pursuant to section 1.9.4A(b)(i), the Office of the Interconnection shall notify the affected Transmission Owner of such request(s). The affected Transmission Owner shall determine in its sole discretion whether to accelerate or reschedule the transmission outage. In making this determination, the affected Transmission Owner shall follow Good Utility Practice, applicable Occupational Safety and Health Administration standards, and applicable company safety standards and shall consider any requirements contained in pertinent collective bargaining agreements. If the affected Transmission Owner determines to accelerate or reschedule the transmission outage, it shall provide the Office of the Interconnection, within the time set forth in the PJM Manuals, an Acceleration Estimate. In the event that Market Participants submit requests which would require different schedules for a transmission outage, the Office of the Interconnection, in consultation with the affected Transmission Owner, shall determine the most effective option, which will be included in the Acceleration Estimate.

(iii) Notification of Acceleration Estimate. Upon receipt of the Acceleration Estimate and verification that Market Participants requesting acceleration or rescheduling of transmission outages have met reasonable creditworthiness standards established by the Office of the Interconnection, the Office of the Interconnection shall provide the Market Participants with the Acceleration Estimate and the number of Market Participants

requesting acceleration or rescheduling of the transmission outage that meet the creditworthiness standards. After receipt of the Acceleration Request, within the time period set forth in the PJM Manuals, each requesting Market Participant meeting the creditworthiness standards shall notify the Office of the Interconnection whether it desires to accelerate or reschedule the transmission outage as set forth in the Acceleration Estimate, and if it desires to accelerate or reschedule the transmission outage, the amount it is willing to pay for such acceleration or rescheduling.

(iv) Evaluation of Acceleration Requests. Upon receipt of Market Participant(s) notifications pursuant to subsection 1.9.4A(b)(iii), the Office of the Interconnection shall determine, based on the amount Market Participants collectively are willing to pay for accelerating or rescheduling of the transmission outage, whether the transmission outage should be accelerated or rescheduled. The transmission outage shall be accelerated or rescheduled if the amount that the Market Participants collectively are willing to pay for accelerating or rescheduling a transmission outage exceeds the Acceleration Estimate by the following margins: (a) for outages to equipment outside a substation, two times the Acceleration Estimate; and (b) for outages to equipment inside a substation, five times the Acceleration Estimate. These margins are designed to provide a reasonable degree of certainty that the actual costs of accelerating or rescheduling the transmission outage will not exceed the amount the Market Participants are willing to pay. In all events, transmission outages will be accelerated or rescheduled pursuant to requests made under section 1.9.4A(c) only when the requested acceleration or rescheduling would reduce the amount of congestion revenue inadequacy resulting from the outage as determined by the Office of the Interconnection.

(v) Cost Responsibility. Each Market Participant which notifies the Office of the Interconnection pursuant to section 1.9.4A(b)(iii) that it is willing to pay for the acceleration or rescheduling of a transmission outage shall be responsible for the actual costs of such acceleration or rescheduling on a pro-rata basis based on the amount it specified it was willing to pay for the acceleration or rescheduling. Market Participants' cost responsibility is not relieved, if, despite the good faith efforts of the Transmission Owner, the amount of costs set forth in the Acceleration Estimate is exceeded by less than 20 percent, or the Transmission Owner is unable successfully to complete a transmission outage pursuant to the revised schedule set forth in the Acceleration Estimate. Prior to incurring costs exceeding 120 percent of the cost estimate set forth in the Acceleration Estimate, the affected Transmission Owner shall advise the Office of the Interconnection of such increase, and the Office of the Interconnection then shall notify the affected Market Participants of such increase. Within the time period set forth in the PJM Manuals, each affected Market Participant shall inform the Office of the Interconnection whether it desires to continue with the revised transmission outage schedule and pay the additional costs. The Office of the Interconnection then shall notify the affected Transmission Owner of each affected Market Participant's decision. In the event that, because one or more Market Participants determine not to proceed, there would be insufficient funds to pay for the full cost of accelerating or rescheduling a transmission outage, the transmission outage shall not continue to be accelerated or rescheduled and shall occur according to normal work practices. In such instance, the Market Participants shall be responsible on a pro-rata basis

for all incurred costs and committed costs and obligations of the affected Transmission Owner as of the date the affected Transmission Owner notified the Office of the Interconnection of the increase in costs.

(d) **Posting Revised Transmission Outages.** The Office of the Interconnection shall post on its internet site all revised transmission outage schedules resulting from implementation of this section 1.9.4A, pursuant to the procedures in the PJM Manuals, and simultaneously shall notify affected Market Participants or Generation Owners that submitted Acceleration Requests of the Transmission Owner's agreement to accelerate or reschedule the outage.

1.9.5 Market Participant Responsibilities.

Each Market Participant making a bilateral sale covering a period greater than the following Operating Day from a generating resource located within the PJM Region for delivery outside the PJM Region shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered.

1.9.6 Internal Market Buyer Responsibilities.

Each Internal Market Buyer making a bilateral purchase covering a period greater than the following Operating Day shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered. Each Internal Market Buyer shall provide the Office of the Interconnection with details of any load management agreements with customers that allow the Office of the Interconnection to reduce load under specified circumstances.

1.9.7 Market Seller Responsibilities.

(a) Not less than 30 days before a Market Seller's initial offer to sell energy from a given generation resource on the PJM Interchange Energy Market, the Market Seller shall furnish to the Office of the Interconnection the information specified in the Offer Data for new generation resources.

(b) Market Sellers authorized to request market-based Start-up Costs and No-load Costs may choose to submit such fees on either a market or a cost basis. Market Sellers must elect to submit both Start-up Costs and No-load Costs on either a market basis or a cost basis and any such election shall be submitted on or before March 31 for the period of April 1 through September 30, and on or before September 30 for the period October 1 through March 31. The election of market-based or cost-based Start-up Costs and No-load Costs shall remain in effect without change throughout the applicable periods.

(i) If a Market Seller chooses to submit market-based Start-up Costs and No-load Costs, such Market Seller, in its Offer Data, shall submit the level of such fees to the Office of the Interconnection for each generating unit as to which the Market Seller intends

to request such fees. The Office of the Interconnection shall reject any request for Start-up Costs and No-load Costs in a Market Seller's Offer Data that does not conform to the Market Seller's specification on file with the Office of the Interconnection.

(ii) If a Market Seller chooses to submit cost-based Start-up Costs and No-load Costs, such fees must be calculated as specified in the PJM Manuals and the Market Seller may change both cost-based fees hourly and must change both fees as the associated costs change, but no more frequently than daily.

1.9.8 Transmission Owner Responsibilities.

[Reserved.]

1.9.9 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall perform seasonal operating studies to assess the forecasted adequacy of generating reserves and of the transmission system, in accordance with the procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall maintain and update tables setting forth Operating Reserve and other reserve objectives as specified in the PJM Manuals and as consistent with the Reliability Assurance Agreement.

(c) The Office of the Interconnection shall receive and process requests for firm and non-firm transmission service in accordance with procedures specified in the PJM Tariff.

(d) The Office of the Interconnection shall maintain such data and information relating to generation and transmission facilities in the PJM Region as may be necessary or appropriate to conduct the scheduling and dispatch of the PJM Interchange Energy Market and PJM Region.

(e) [Reserved.]

(f) The Office of the Interconnection shall coordinate with other interconnected Control Area as necessary to manage, alleviate or end an Emergency.

1.10 Scheduling.

1.10.1 General.

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

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

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

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

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of

conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of *Tariff, Attachment K-Appendix*, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with *Tariff, Attachment K-Appendix*, section 3.2.3 and *Tariff, Attachment K-Appendix*, section 6.6.

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

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

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

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

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

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

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum

difference between the source and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

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

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

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

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on

either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

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

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

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

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

The foregoing offers:

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

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

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

Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

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

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

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

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

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

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

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

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

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

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

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

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

- i. The costs (in \$/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;
- ii. The cost increase (in \$/ Δ MW) 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 *Tariff, Attachment K-Appendix, section 3.2.3* and *Tariff, Attachment K-Appendix, section 6.6*.

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

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

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

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

(1) *Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit*

offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

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

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of

implementation of this rule the expected value of the penalty shall be \$0.02/MWh, and for the period from the second month after implementation through the second January 1 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

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

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

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

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

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

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

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

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available

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

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

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

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

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

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

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

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

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

reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

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

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

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

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

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available

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

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

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

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to

support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provide reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

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

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

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

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

such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

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

1.10.1B Demand Bid Scheduling and Screening

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

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

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

Where:

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

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

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load

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

1.10.2 Pool-scheduled Resources.

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

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

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

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

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

the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

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

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

1.10.3 Self-scheduled Resources.

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

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

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

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

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

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

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

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

1.10.4 Capacity Resources.

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

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

1.10.5 External Resources.

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

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability;

(iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

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

1.10.6 External Market Buyers.

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

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

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

1.10.7 Bilateral Transactions.

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

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the

Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; (viii) Ambient-Adjusted Ratings for Transmission Facilities; and (ix) 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 *Tariff, Attachment K-Appendix*, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market utilizing security constrained unit commitment and security constrained economic dispatch software 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 *Tariff, Attachment K-Appendix*, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to *Tariff, Attachment K-Appendix*, section 2.4 and *Tariff, Attachment K-Appendix*, section 2.5.

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

(f) Consistent with *Operating Agreement*, section 18.17.1, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and

Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

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

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

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

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

the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

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

1.10.9A Updating Offers in Real-time

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

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

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

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

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3)

emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) *Synchronized Reserve maximum MW*; and (8) *Secondary Reserve maximum MW*. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

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

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

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

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

1.11 Real-time Dispatch.

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

- (a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Tariff, Attachment K-Appendix, section 1.7.6), the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints. In addition, the Office of the Interconnection shall utilize Ambient-Adjusted Ratings for Transmission Facilities as an input into the real-time security constrained economic dispatch.
- (b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.
- (c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and

consistent representation of generator outputs, loads, and power flows on the network. In performing the security constrained economic dispatch of the system, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program. The State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, which shall provide the megawatt output of generators and the loads at buses in the PJM Region, transmission line losses, and actual flows or loadings on transmission facilities as defined in the PJM Manuals.

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time security constrained economic dispatch program or other operational reasons, the most recent State

Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of

the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Economic Load Response Participant resources will be zero.

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

1.11.4A Synchronized Reserve.

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

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

Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

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

1.11.4B Non-Synchronized Reserve.

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

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

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation resources

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

1.11.4C Secondary Reserve.

- (a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants.
- (b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.
- (c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of,

their generation resources supplying energy in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

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

1.11.6 Real-time Energy Market Suspension.

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

ATTACHMENT W

Transmission Facility Ratings

GENERAL

The Office of the Interconnection and the Transmission Owners will implement Transmission Facility Ratings on the Transmission Facilities over which the Office of the Interconnection provides Transmission Service, as provided below.

As required by the Consolidated Transmission Owners Agreement, each Transmission Owner provides PJM with its respective Transmission Facility Ratings and PJM reviews and implements the applicable Transmission Facility Rating(s) consistent with this Tariff, Attachment W, the Consolidated Transmission Owners Agreement, and the PJM Manuals.

Use of temporary conditional Transmission Facility Ratings to Ensure the Safety and Reliability of the Transmission System (System Reliability):

If the Office of the Interconnection or Transmission Owner reasonably determines, consistent with Good Utility Practice, that the temporary conditional use of a Transmission Facility Rating different than would otherwise be required by this Attachment is necessary to ensure the safety and reliability of the Transmission System, including the application of a surrogate rating override to the Transmission Facility Rating representing an equivalent voltage or stability limit, such as, but not exclusive to, that which is identified in Tariff, Attachment C, then the Office of the Interconnection or Transmission Owner may use such a temporary conditional rating. The entity that makes this determination must document in the Office of the Interconnection's database of Transmission Facility Ratings and Transmission Facility Rating methodologies on OASIS or another password-protected website, as required by this Attachment, the use of an alternate Transmission Facility Rating under this paragraph, including the nature of and basis for the temporary conditional rating, the date and time that the alternate rating was initiated, and (if applicable) the date and time that the alternate rating was withdrawn and the standard rating became effective again.

Obligations of the Office of the Interconnection:

The Office of the Interconnection will have the following obligations:

The Office of the Interconnection must use AARs, or AAR Exceptions where appropriate, as the relevant Transmission Facility Ratings when performing any of the following functions: (1) evaluating requests for Near-Term Transmission Service; (2) responding to requests for information on the availability of potential Near-Term Transmission Service (including requests for ATC or other information related to potential service); or (3) posting ATC or other information related to Near-Term

Transmission Service to the Office of the Interconnection's OASIS site or another password-protected website.

The Office of the Interconnection must use AARs, or AAR Exceptions where appropriate, as the relevant Transmission Facility Ratings when determining whether to curtail (Tariff, Part II, section 13.6) Firm Point-To-Point Transmission Service or when determining whether to curtail and/or interrupt (Tariff, Part II, section 14.7) Non-Firm Point-To-Point Transmission Service if such curtailment and/or interruption is both necessary because of issues related to flow limits on Transmission Facilities and anticipated to occur (start and end) within 10 days of such determination. For determining whether to curtail or interrupt Point-To-Point Transmission Service in other situations, the Office of the Interconnection must use Seasonal Facility Ratings as the relevant Transmission Facility Ratings.

The Office of the Interconnection must use AARs, or AAR Exceptions where appropriate, as the relevant Transmission Facility Ratings when determining whether to curtail (Tariff, Part III, section 33) or redispatch (Tariff, Part III, section 30.5 and/or Tariff, Part III, section 33) Network Integration Transmission Service or secondary service if such curtailment or redispatch is both necessary because of issues related to flow limits on Transmission Facilities and anticipated to occur (start and end) within 10 days of such determination. For determining the necessity of curtailment or redispatch of Network Integration Transmission Service or secondary service in other situations, the Office of the Interconnection must use Seasonal Facility Ratings as the relevant Transmission Facility Ratings.

The Office of the Interconnection must use Seasonal Facility Ratings as the relevant Transmission Facility Ratings when evaluating requests for and whether to curtail, interrupt, or redispatch any Transmission Service not otherwise covered above in this section (including, but not limited to, requests for non-Near-Term Transmission Service or requests to designate or change the designation of Network Resources or Network Load), when developing any ATC or other information posted or provided to potential customers related to such services. The Office of the Interconnection must use Seasonal Facility Ratings as a recourse rating in the event that an AAR otherwise required to be used under this Attachment is unavailable.

The Office of the Interconnection must use uniquely determined Emergency Ratings for contingency analysis in the operations horizon and in post-contingency simulations of constraints. Such uniquely determined Emergency Ratings must also include separate AAR for each Emergency Rating duration used.

Any forecasts of ambient air temperature for AARs and Seasonal Facility Ratings developed by the Office of the Interconnection or the Transmission Owner must be developed consistent with Good Utility Practice and on a non-discriminatory basis.

Postings to the Office of the Interconnection's OASIS or another password-protected website: The Office of the Interconnection must maintain on the password-protected section of its OASIS page or on another password-protected website a database of

Transmission Facility Ratings and Transmission Facility Rating methodologies. This database must be accessible to the Market Monitoring Unit. The database must include a full record of all Transmission Facility Ratings, both as used in real-time operations, and as used for all future periods for which Transmission Service is offered. Any postings of temporary alternate Transmission Facility Ratings or exceptions used under the System Reliability section above or the Exceptions section below, respectively, are considered part of the database. The database must include records of which Transmission Facility Ratings and Transmission Facility Rating methodologies were in effect at which times over at least the previous five years, including records of which temporary alternate Transmission Facility Ratings or exceptions were in effect at which times during the previous five years. Each record in the database must indicate which Transmission Facility the record applies to, and the date and time the record was entered into the database. The database must be maintained such that users with OASIS access or access to the password-protected website can view, download, and query data in standard formats, using standard protocols.

Sharing with Transmission Providers: The Office of the Interconnection must share, upon request by any Transmission Provider and in a timely manner, the following information:

- (1) Transmission Facility Ratings for each period for which Transmission Facility Ratings are evaluated, with updated ratings shared each time Transmission Facility Ratings are evaluated, and
- (2) Written Transmission Facility Rating methodologies used in arriving at the Transmission Facility Ratings in (1) above.

AAR Exceptions:

Where the Transmission Owner determines, consistent with Good Utility Practice, that the Transmission Facility Rating of a Transmission Facility is not affected by ambient air temperature or solar heating, the Office of the Interconnection and Transmission Owner may use a Transmission Facility Rating for that Transmission Facility that is not an AAR or Seasonal Transmission Facility Rating, including consideration for the technical limitations of the transmission system (such as system voltage or stability limits). Examples of such a Transmission Facility may include (but are not limited to): (1) a Transmission Facility for which the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperature or solar heating; or (2) a Transmission Facility whose transfer capability is limited by a Transmission System limit (such as a system voltage or stability limit) which is not dependent on ambient air temperature or solar heating. The entity that makes this determination must document in the Office of the Interconnection's database of Transmission Facility Ratings and Transmission Facility Rating methodologies on OASIS or another password-protected website any exceptions to the requirements contained in this Attachment initiated under this paragraph, including the nature of and basis for each exception, the date(s) and time(s) that the exception was initiated, and (if applicable) the date(s) and time(s) that each exception was withdrawn and the standard

rating became effective again. If the technical basis for an exception under this paragraph changes, then the Transmission Owner must update the relevant Transmission Facility Rating(s) in a timely manner. The Transmission Owner must reevaluate any exceptions taken under this paragraph at least every five years.

SCHEDULE 1
Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider. The charges for Scheduling, System Control and Dispatch Service from PJM Interconnection, L.L.C. are set forth on an unbundled basis among the subsidiary schedules of Tariff, Schedule 9 "PJM Interconnection, L.L.C. Administrative Services".

1.9 Prescheduling.

The following procedures and principles shall govern the prescheduling activities necessary to plan for the reliable operation of the PJM Region and for the efficient operation of the PJM Interchange Energy Market.

1.9.1 Outage Scheduling.

The Office of the Interconnection shall be responsible for coordinating and approving requests for outages of generation and transmission facilities as necessary for the reliable operation of the PJM Region, in accordance with the PJM Manuals. The Office of the Interconnection shall maintain records of outages and outage requests of these facilities.

1.9.2 Planned Outages.

(a) A Generator Planned Outage shall be included in Generator Planned Outage schedules established prior to the scheduled start date for the outage, in accordance with standards and procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall conduct Generator Planned Outage scheduling for Generation Capacity Resources in accordance with the Reliability Assurance Agreement and the PJM Manuals and in consultation with the Market Sellers owning or controlling the output of such resources. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from all or part of a generation resource undergoing an approved Generator Planned Outage. If the Office of the Interconnection determines that approval of a Generator Planned Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval or withdraw a prior approval. Approval of a Generator Planned Outage of a Generation Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. The Market Seller shall provide the Office of the Interconnection with an estimate of the amount of time it needs to return to service any Generation Capacity Resource on Generator Planned Outage that is already underway. If the Office of the Interconnection withdraws its approval of a Generator Planned Outage, it shall coordinate with the Market Seller owning or controlling the resource to reschedule the Generator Planned Outage at the earliest practical time. The Office of the Interconnection shall if possible propose alternative schedules with the intent of minimizing the economic impact on the Market Seller of a Generator Planned Outage.

(c) The Office of the Interconnection shall conduct Transmission Planned Outage scheduling in accordance with procedures specified in the Consolidated Transmission Owners Agreement and the PJM Manuals, and in accordance with the following procedures:

(i) Transmission Owners shall use reasonable efforts to submit Transmission Planned Outage schedules one year in advance but by no later than the first of the month six months in advance of the requested start date for all outages that are expected to

exceed five working days duration, with regular (at least monthly) updates as new information becomes available.

- (ii) If notice of a Transmission Planned Outage is not provided in accordance with the requirements in subsection (i) above, and if such outage is determined by the Office of the Interconnection to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid such impacts. The Office of the Interconnection may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under the Operating Agreement or PJM Tariff and provided the Office of the Interconnection determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had the Office of the Interconnection implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. The Office of the Interconnection may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from the Office of the Interconnection's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in the Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.
- (iii) Transmission Owners shall submit notice of all Transmission Planned Outages to the Office of the Interconnection by the first day of the month preceding the month the outage will commence, with updates as new information becomes available.
- (iv) If notice of a Transmission Planned Outage is not provided by the first day of the month preceding the month the outage will commence, and if such outage is determined by the Office of the Interconnection to have the potential to cause significant system impacts, including but not limited to reliability impacts and transmission system congestion, then the Office of the Interconnection may require the Transmission Owner to implement an alternative outage schedule to reduce or avoid such impacts. The Office of the Interconnection shall perform this analysis and notify the Transmission Owner in a timely manner if it will require rescheduling of the outage. The Office of the Interconnection may, however, if requested by the Transmission Owner, dispatch generation or reductions in demand in order to avoid implementing an alternative outage schedule for its Transmission Facilities to extent consistent with its obligations under the Operating Agreement or PJM Tariff and provided the Office of the Interconnection determines that such dispatch would not adversely affect reliability in the PJM Region or otherwise not be in accordance with Good Utility Practices. A Transmission Owner that makes

such a dispatch request pursuant to this section shall be responsible for all generation and other costs resulting from its request that would not have been incurred had the Office of the Interconnection implemented an alternative outage schedule to reduce or avoid reliability and congestion impacts. The Office of the Interconnection may, at the Transmission Owner's consent, directly assign to the Transmission Owner all generation and other costs resulting from the Office of the Interconnection's dispatch of generation or reductions in demand arising from outages associated with RTEP upgrades not submitted consistent with the timelines set forth in the Tariff and the PJM Operating Agreement and where such outage is required to meet the reliability-based in-service date of the RTEP upgrade project.

- (v) The Office of the Interconnection reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure reliable system operations on a case by case basis regardless of duration or date of submission.
- (vi) The Office of the Interconnection shall post notice of Transmission Planned Outages on OASIS upon receipt of such notice from the Transmission Owner; provided, however, that the Office of the Interconnection shall not post on OASIS notice of any component of a Transmission Planned Outage to the extent such component shall directly reveal a generator outage. In such cases, the Transmission Owner, in addition to providing notice to the Office of the Interconnection as required above, concurrently shall inform the affected Generation Owner of such outage, limiting such communication to that necessary to describe the outage and to coordinate with the Generation Owner on matters of safety to persons, facilities, and equipment. The Transmission Owner shall not notify any other Market Participant of such outage and shall arrange any other necessary coordination through the Office of the Interconnection.

In addition, if the Office of the Interconnection determines that transmission maintenance schedules proposed by one or more Members would significantly affect the efficient and reliable operation of the PJM Region, the Office of the Interconnection may establish alternative schedules, but such alternative shall minimize the economic impact on the Member or Members whose maintenance schedules the Office of the Interconnection proposes to modify.

- (d) The Office of the Interconnection shall coordinate resolution of outage or other planning conflicts that may give rise to unreliable system conditions. The Members shall comply with all maintenance schedules established by the Office of the Interconnection.

1.9.3 Generator Maintenance Outages.

- (a) A Generator Maintenance Outage may only be scheduled if approved by the Office of the Interconnection prior to the requested start date for the outage, in accordance with subsection (b) hereof and the standards and procedures specified in the PJM Manuals.
- (b) The Office of the Interconnection shall schedule Generator Maintenance Outages for Generation Capacity Resources in accordance with the procedures specified in the PJM Manuals and in consultation with the Market Seller owning or controlling the output of such resources. The

Office of the Interconnection shall approve requests for Generator Maintenance Outages for such a Generation Capacity Resource unless the outage would threaten the adequacy of reserves in, or the reliability of, the PJM Region. A Market Participant shall not be expected to submit offers for the sale of energy or other services, or to satisfy delivery obligations, from a generation resource undergoing an approved full or partial Generator Maintenance Outage. If the Office of the Interconnection determines that approval of a Generator Maintenance Outage would significantly affect the reliable operation of the PJM Region, the Office of the Interconnection may withhold approval, withdraw a prior approval, or rescind a prior approval of a Generator Maintenance Outage that is already underway. Approval of a Generator Maintenance Outage of a Generation Capacity Resource shall be withheld or withdrawn only as necessary to ensure the adequacy of reserves or the reliability of the PJM Region in connection with anticipated implementation or avoidance of Emergency procedures. In addition, if the Office of the Interconnection determines that it must rescind its approval of a Generator Maintenance Outage that is already underway in order to preserve the reliable operation of the PJM Region, the Office of the Interconnection will provide the Market Seller of the Generation Capacity Resource at least 72 hours' notice thereof. The Market Seller shall be required to make the Generation Capacity Resource available for normal operation within 72 hours of such notice. If the generator is not made available for normal operation by 72 hours after the notice of the rescission of the approval of the Generator Maintenance Outage, for the remaining time the resource continues on the outage it shall be deemed to have experienced a Generator Forced Outage. If the Office of the Interconnection withholds, withdraws or rescinds approval of a Generator Maintenance Outage, it shall coordinate with the Market Seller owning or controlling the resource to reschedule the Generator Maintenance Outage at the earliest practical time. The Office of the Interconnection shall, if possible, propose alternative schedules with the intent of minimizing the economic impact on the Market Seller of a Generator Maintenance Outage.

1.9.4 Forced Outages.

(a) Each Market Seller that owns or controls a pool-scheduled resource, or Generation Capacity Resource whether or not pool-scheduled, shall: (i) advise the Office of the Interconnection of a Generator Forced Outage suffered or anticipated to be suffered by any such resource as promptly as possible; (ii) provide the Office of the Interconnection with the expected date and time that the resource will be made available; and (iii) make a record of the events and circumstances giving rise to the Generator Forced Outage. A Market Seller shall not be expected to submit offers for the sale of energy or other services, or satisfy delivery obligations, from a generation resource undergoing a Generator Forced Outage. A Generation Capacity Resource committed to PJM loads through an RPM Auction, FRR Capacity Plan, or by designation as a replacement resource under Attachment DD of the PJM Tariff, that does not deliver all or part of its scheduled energy shall be deemed to have experienced a Generator Forced Outage with respect to such undelivered energy, in accordance with standards and procedures for full and partial Generator Forced Outages specified in the Reliability Assurance Agreement, and the PJM Manuals.

(b) The Office of the Interconnection shall receive notification of Forced Transmission Outages, and information on the return to service, of Transmission Facilities in the PJM Region in

accordance with standards and procedures specified in, as applicable, the Consolidated Transmission Owners Agreement and the PJM Manuals.

1.9.4A Transmission Outage Acceleration.

(a) Planned Transmission Outages and Forced Transmission Outages otherwise scheduled pursuant to sections 1.9.2 and 1.9.4 respectively of this Schedule may be accelerated or rescheduled at the request of a Generation Owner or other Market Participant in accordance with the terms and conditions of this section 1.9.4A and the PJM Manuals.

(b) Transmission Outages Requiring Coordination With A Specific Generation Owner.

- (i) Receipt of Acceleration Request. Prior to a scheduled Planned Transmission Outage associated with the interconnection of a generating unit to the Transmission System, the affected Generation Owner may request that the outage be accelerated or rescheduled. Such Acceleration Request shall be submitted to the Office of the Interconnection in accordance with the procedures set forth in the PJM Manuals.
- (ii) Determination to Accommodate Acceleration Request. Upon receipt of an Acceleration Request, the Office of the Interconnection shall notify the affected Transmission Owner of such Acceleration Request. The affected Transmission Owner shall determine, in its sole discretion, whether to accelerate or reschedule a transmission outage. In making this determination, the affected Transmission Owner shall follow Good Utility Practice, applicable Occupational Safety and Health Administration standards, and applicable company safety standards, and shall consider any requirements contained in pertinent collective bargaining agreements. In the event that the affected Transmission Owner determines to accelerate or reschedule a transmission outage, it shall provide the Office of the Interconnection, within the time set forth in the PJM Manuals, an estimate of the cost to accelerate or reschedule the transmission outage and the revised schedule for the transmission outage (“Acceleration Estimate”).
- (iii) Provision of Acceleration Estimate. Upon receipt of the Acceleration Estimate and verification that the Generation Owner has met reasonable creditworthiness standards established by the Office of the Interconnection, the Office of the Interconnection shall provide the Generation Owner with the Acceleration Estimate. In the event that the Generation Owner does not meet the creditworthiness standard, the Office of the Interconnection shall not provide the Acceleration Estimate and the transmission outage shall not be accelerated or rescheduled. Upon receipt of the Acceleration Estimate, the Generation Owner, within the time period specified in the PJM Manuals, shall notify the Office of the Interconnection as to whether it desires to accelerate or reschedule the transmission outage pursuant to the terms of the Acceleration Estimate.

(iv) Cost Responsibility. In the event the Generation Owner notifies the Office of the Interconnection that it desires to proceed with the acceleration or rescheduling of the transmission outage pursuant to section 1.9.4A(a)(iii), the Generation Owner shall be solely responsible for actual costs incurred by the affected Transmission Owner for the acceleration or rescheduling of the transmission outage. The Generation Owner's cost responsibility is not relieved, if, despite the good faith efforts of the Transmission Owner, the amount of costs set forth in the Acceleration Estimate is exceeded by less than 20 percent, or the Transmission Owner is unable successfully to complete the outage pursuant to the revised schedule set forth in the Acceleration Estimate. Prior to incurring costs exceeding 120 percent of the cost estimate set forth in the Acceleration Estimate, the affected Transmission Owner shall advise the Office of the Interconnection of such increase, and the Office of the Interconnection then shall notify the Generation Owner. After receipt of such notification, within the time period set forth in the PJM Manuals, the Generation Owner shall inform the Office of the Interconnection whether it desires to continue with the revised transmission outage schedule and pay the additional costs. The Office of the Interconnection shall notify the affected Transmission Owner of the Generation Owner's decision. In the event the Generation Owner desires not to proceed, the transmission outage shall occur according to normal work practices and the Generation Owner shall be responsible for all incurred costs and committed costs and obligations of the affected Transmission Owner for the acceleration or rescheduling of the transmission outage as of the date that the affected Transmission Owner notified the Office of the Interconnection of the increase in costs.

(c) Transmission Outages That Could Cause Congestion Revenue Inadequacy.

- (i) Posting of Transmission Outage. In the event that the Office of the Interconnection determines that a Planned Transmission Outage or Forced Transmission Outage could exceed five days and could cause congestion revenue inadequacy in excess of \$500,000, the Office of the Interconnection shall post a notice of such transmission outage on its internet site. Within the time period and pursuant to the procedures set forth in the PJM Manuals, any Market Participant may request that such transmission outage be accelerated or rescheduled.
- (ii) Determination to Accelerate or Reschedule Transmission Outage. Upon receipt of the Acceleration Request(s) pursuant to section 1.9.4A(b)(i), the Office of the Interconnection shall notify the affected Transmission Owner of such request(s). The affected Transmission Owner shall determine in its sole discretion whether to accelerate or reschedule the transmission outage. In making this determination, the affected Transmission Owner shall follow Good Utility Practice, applicable Occupational Safety and Health

Administration standards, and applicable company safety standards and shall consider any requirements contained in pertinent collective bargaining agreements. If the affected Transmission Owner determines to accelerate or reschedule the transmission outage, it shall provide the Office of the Interconnection, within the time set forth in the PJM Manuals, an Acceleration Estimate. In the event that Market Participants submit requests which would require different schedules for a transmission outage, the Office of the Interconnection, in consultation with the affected Transmission Owner, shall determine the most effective option, which will be included in the Acceleration Estimate.

- (iii) Notification of Acceleration Estimate. Upon receipt of the Acceleration Estimate and verification that Market Participants requesting acceleration or rescheduling of transmission outages have met reasonable creditworthiness standards established by the Office of the Interconnection, the Office of the Interconnection shall provide the Market Participants with the Acceleration Estimate and the number of Market Participants requesting acceleration or rescheduling of the transmission outage that meet the creditworthiness standards. After receipt of the Acceleration Request, within the time period set forth in the PJM Manuals, each requesting Market Participant meeting the creditworthiness standards shall notify the Office of the Interconnection whether it desires to accelerate or reschedule the transmission outage as set forth in the Acceleration Estimate, and if it desires to accelerate or reschedule the transmission outage, the amount it is willing to pay for such acceleration or rescheduling.
- (iv) Evaluation of Acceleration Requests. Upon receipt of Market Participant(s) notifications pursuant to subsection 1.9.4A(b)(iii), the Office of the Interconnection shall determine, based on the amount Market Participants collectively are willing to pay for accelerating or rescheduling of the transmission outage, whether the transmission outage should be accelerated or rescheduled. The transmission outage shall be accelerated or rescheduled if the amount that the Market Participants collectively are willing to pay for accelerating or rescheduling a transmission outage exceeds the Acceleration Estimate by the following margins: (a) for outages to equipment outside a substation, two times the Acceleration Estimate; and (b) for outages to equipment inside a substation, five times the Acceleration Estimate. These margins are designed to provide a reasonable degree of certainty that the actual costs of accelerating or rescheduling the transmission outage will not exceed the amount the Market Participants are willing to pay. In all events, transmission outages will be accelerated or rescheduled pursuant to requests made under section 1.9.4A(c) only when the requested acceleration or rescheduling would reduce the amount of congestion revenue inadequacy resulting from the outage as determined by the Office of the Interconnection.

(v) Cost Responsibility. Each Market Participant which notifies the Office of the Interconnection pursuant to section 1.9.4A(b)(iii) that it is willing to pay for the acceleration or rescheduling of a transmission outage shall be responsible for the actual costs of such acceleration or rescheduling on a pro-rata basis based on the amount it specified it was willing to pay for the acceleration or rescheduling. Market Participants' cost responsibility is not relieved, if, despite the good faith efforts of the Transmission Owner, the amount of costs set forth in the Acceleration Estimate is exceeded by less than 20 percent, or the Transmission Owner is unable successfully to complete a transmission outage pursuant to the revised schedule set forth in the Acceleration Estimate. Prior to incurring costs exceeding 120 percent of the cost estimate set forth in the Acceleration Estimate, the affected Transmission Owner shall advise the Office of the Interconnection of such increase, and the Office of the Interconnection then shall notify the affected Market Participants of such increase. Within the time period set forth in the PJM Manuals, each affected Market Participant shall inform the Office of the Interconnection whether it desires to continue with the revised transmission outage schedule and pay the additional costs. The Office of the Interconnection then shall notify the affected Transmission Owner of each affected Market Participant's decision. In the event that, because one or more Market Participants determine not to proceed, there would be insufficient funds to pay for the full cost of accelerating or rescheduling a transmission outage, the transmission outage shall not continue to be accelerated or rescheduled and shall occur according to normal work practices. In such instance, the Market Participants shall be responsible on a pro-rata basis for all incurred costs and committed costs and obligations of the affected Transmission Owner as of the date the affected Transmission Owner notified the Office of the Interconnection of the increase in costs.

(d) Posting Revised Transmission Outages. The Office of the Interconnection shall post on its internet site all revised transmission outage schedules resulting from implementation of this section 1.9.4A, pursuant to the procedures in the PJM Manuals, and simultaneously shall notify affected Market Participants or Generation Owners that submitted Acceleration Requests of the Transmission Owner's agreement to accelerate or reschedule the outage.

1.9.5 Market Participant Responsibilities.

Each Market Participant making a bilateral sale covering a period greater than the following Operating Day from a generating resource located within the PJM Region for delivery outside the PJM Region shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered.

1.9.6 Internal Market Buyer Responsibilities.

Each Internal Market Buyer making a bilateral purchase covering a period greater than the following Operating Day shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered. Each Internal Market Buyer shall provide the Office of the Interconnection with details of any load management agreements with customers that allow the Office of the Interconnection to reduce load under specified circumstances.

1.9.7 Market Seller Responsibilities.

(a) Not less than 30 days before a Market Seller's initial offer to sell energy from a given generation resource on the PJM Interchange Energy Market, the Market Seller shall furnish to the Office of the Interconnection the information specified in the Offer Data for new generation resources.

(b) Market Sellers authorized to request market-based Start-up Costs and No-load Costs may choose to submit such fees on either a market or a cost basis. Market Sellers must elect to submit both Start-up Costs and No-load Costs on either a market basis or a cost basis and any such election shall be submitted on or before March 31 for the period of April 1 through September 30, and on or before September 30 for the period October 1 through March 31. The election of market-based or cost-based Start-up Costs and No-load Costs shall remain in effect without change throughout the applicable periods.

- (i) If a Market Seller chooses to submit market-based Start-up Costs and No-load Costs, such Market Seller, in its Offer Data, shall submit the level of such fees to the Office of the Interconnection for each generating unit as to which the Market Seller intends to request such fees. The Office of the Interconnection shall reject any request for Start-up Costs and No-load Costs in a Market Seller's Offer Data that does not conform to the Market Seller's specification on file with the Office of the Interconnection.
- (ii) If a Market Seller chooses to submit cost-based Start-up Costs and No-load Costs, such fees must be calculated as specified in the PJM Manuals and the Market Seller may change both cost-based fees hourly and must change both fees as the associated costs change, but no more frequently than daily.

1.9.8 Transmission Owner Responsibilities.

[Reserved.]

1.9.9 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall perform seasonal operating studies to assess the forecasted adequacy of generating reserves and of the transmission system, in accordance with the procedures specified in the PJM Manuals.

(b) The Office of the Interconnection shall maintain and update tables setting forth Operating Reserve and other reserve objectives as specified in the PJM Manuals and as consistent with the Reliability Assurance Agreement.

(c) The Office of the Interconnection shall receive and process requests for firm and non-firm transmission service in accordance with procedures specified in the PJM Tariff.

(d) The Office of the Interconnection shall maintain such data and information relating to generation and transmission facilities in the PJM Region as may be necessary or appropriate to conduct the scheduling and dispatch of the PJM Interchange Energy Market and PJM Region.

(e) [Reserved.]

(f) The Office of the Interconnection shall coordinate with other interconnected Control Area as necessary to manage, alleviate or end an Emergency.

1.10 Scheduling.

1.10.1 General.

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

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

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

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

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

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly

energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of *Operating Agreement, Schedule 1*, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with *Operating Agreement, Schedule 1*, section 3.2.3 and *Operating Agreement, Schedule 1*, section 6.6.

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

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

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

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

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

- i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;
- ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to *Operating Agreement, Schedule 1*, section 1.12; and
- iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source

and sink prices that a participant may specify shall be limited to +/- \$50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

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

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

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

- i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This

includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

- ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.
- iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.
- iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

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

The foregoing offers:

- i) Shall specify the Generation Capacity Resource or *Economic Load Response Participant resource* and energy or demand reduction amount, respectively, for each clock hour in the offer period;
- ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;
- iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) *Synchronized Reserve maximum MW*; (14) *Secondary Reserve maximum MW*; and (15) *condense to generation time constraints*, and may specify offer parameters for *Economic Load Response Participant resources* for each clock hour

during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

- iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;
- v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;
- vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;
- vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;
- viii) Shall not exceed an energy offer price of \$1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above \$1,000/megawatt-hour and less than or equal to \$2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than \$2,000/megawatt-hour, then its market-based offer must be less than or equal to \$2,000/megawatt-hour;
- ix) Shall not exceed a demand reduction offer price of \$1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above \$1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than \$2,000/megawatt-hour;
- x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

- a) a 30 minute lead time, pursuant to *Tariff, Attachment DD-1*, section A.2 and the parallel provision of *RAA*, Schedule 6, \$1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus \$1.00;
- b) an approved 60 minute lead time, pursuant to *Tariff, Attachment DD-1*, section A.2 and the parallel provision of *RAA*, Schedule 6, \$1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and
- c) an approved 120 minute lead time, pursuant to *Tariff, Attachment DD-1*, section A.2 and the parallel provisions of *RAA*, Schedule 6, \$1,100/megawatt-hour; and

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

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

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

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

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

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

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

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

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

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

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

(3) *Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in \$/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the*

probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

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

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

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

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

(2) *An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B)*

Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

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

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

the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

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

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

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

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

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

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

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

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

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

(1) *Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for*

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

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

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

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

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

however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

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

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

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

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

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

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

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for \$0.00/MWh. Offers shall be submitted to the Office of the

Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

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

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

1.10.1B Demand Bid Scheduling and Screening

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

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

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

Where:

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

3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

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

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

1.10.2 Pool-scheduled Resources.

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

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

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

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient

to enable the Office of the Interconnection to determine the available operating hours of such facilities.

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

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

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

1.10.3 Self-scheduled Resources.

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

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

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

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

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not

delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

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

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

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

1.10.4 Capacity Resources.

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

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

1.10.5 External Resources.

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

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

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

1.10.6 External Market Buyers.

- (a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.
- (b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.
- (c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A *above* that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in

the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

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

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

data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

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

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

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market *or Day-ahead Ancillary Services Markets, or the* Real-time Energy Market *or Real-time Ancillary Services Markets* after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market *and Real-time Ancillary Services Markets*, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market *and Day-ahead Ancillary Services Markets*. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Real-time Energy Market *and Real-time Ancillary Services Markets*, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market *and Day-ahead Ancillary Services Markets*. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating

Day for the Day-ahead Energy Market, Real-time Energy Market, *and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets*. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

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

1.10.9 Hourly Scheduling.

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

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

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

- i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;
- ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or
- iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

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

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

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

1.10.9A Updating Offers in Real-time

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

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

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

Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

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

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

1.10.9B Offer Parameter Flexibility

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

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

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

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from

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

1.11 Real-time Dispatch.

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

- (a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6), the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints. In addition, the Office of the Interconnection shall utilize Ambient-Adjusted Ratings for Transmission Facilities as an input into the real-time security constrained economic dispatch.
- (b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.
- (c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and

consistent representation of generator outputs, loads, and power flows on the network. In performing the security constrained economic dispatch of the system, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program. The State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, which shall provide the megawatt output of generators and the loads at buses in the PJM Region, transmission line losses, and actual flows or loadings on transmission facilities as defined in the PJM Manuals.

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time security constrained economic dispatch program or other operational reasons, the most recent State

Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

- (a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request, by following the Day-ahead Market clearing, or by following the direct request of the Market Seller, subject to the Office of the Interconnection's determination of actions necessary to maintain reliability.
- (b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection upon receipt.

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Economic Load Response Participant resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Economic Load Response Participant resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected

value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Economic Load Response Participant resources will be zero.

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

1.11.4A Synchronized Reserve.

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

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

Synchronized Reserve in the Day-ahead Synchronized Reserve Market shall be committed to provide Synchronized Reserve in the Real-time Synchronized Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.

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

1.11.4B Non-Synchronized Reserve.

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

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

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation resources from which Non-Synchronized Reserve is available, in accordance with the PJM Manuals. Market

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

1.11.4C Secondary Reserve.

- (a) A Market Buyer may satisfy its Secondary Reserve Obligation by contractual arrangements with other Market Participants able to provide Secondary Reserve, or by purchases from the PJM Secondary Reserve Market at the rates set forth in Operating Agreement, Schedule 1, section 3.2.3A.01. PJMSettlement shall be the Counterparty to the purchases and sales of Secondary Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants.
- (b) The Office of the Interconnection shall obtain Secondary Reserve from the least-cost alternatives available from pool-scheduled generation resources and/or Economic Load Response Participant resources as needed to meet the 30-minute Reserve Requirements of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by resources providing Synchronized Reserve and resources providing Non-Synchronized Reserve. The Office of the Interconnection shall clear both the Day-ahead Secondary Reserve Market and the Real-time Secondary Reserve Market in accordance with the applicable Operating Reserve Demand Curve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02, the offers submitted in the PJM Interchange Energy Market and the offers submitted in the Secondary Reserve Market. Resources shall be cleared to provide Secondary Reserve on the basis of each generation resource's and/or Economic Load Response Participant resource's Secondary Reserve offer and the product substitution cost between providing Secondary Reserve, energy and any other product the resource is capable of providing, and in accordance with the Office of the Interconnection's obligation to jointly procure and minimize the total production cost of energy and of meeting the Synchronized Reserve Requirements, Primary Reserve Requirements, 30-minute Reserve Requirements, and, in the real-time energy and reserve markets, Regulation Requirement. However, any synchronous condenser or Economic Load Response Participant resource with a notification offer parameter of at least ten minutes greater but no more than 30 minutes, and with a minimum run time (or minimum down time for Economic Load Response Participant resources) no greater than one hour, and which receives a commitment to provide Secondary Reserve in the Day ahead Secondary Reserve Market shall be committed to provide Secondary Reserve in the Real-time Secondary Reserve Market, unless the resource is committed in real-time to provide energy or another reserve product.
- (c) The Office of the Interconnection shall dispatch generation resources and/or Economic Load Response Participant resources for Secondary Reserve by sending Secondary Reserve instructions to generation resources and/or Economic Load Response Participant resources from which Secondary Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying energy in the PJM Region as close to desired output levels as

practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

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

1.11.6 Real-time Energy Market Suspension.

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